Accounting and Billing Manual

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The information contained within this manual, along with the other NYISO manuals, is intended to be used for informational purposes and is subject to change. The NYISO is not responsible for the user's reliance on these publications or for any erroneous or misleading material.

Dedication to Randy Bowers

Randy A. Bowers (1961-2010, NYISO Principal and former Manager of Customer Settlements, was the original author of this Accounting and Billing Manual. His passion for and extensive knowledge of the electric industry, along with his insights and hard work, are evidenced in this manual. It is only fitting that we dedicate this Accounting and Billing Manual to Randy A. Bowers for his vision to the future, dedication to the electric industry, and commitment to excellence.

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Revision History

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1.0	09/03/1999	Initial Release

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Relation of This Manual to NYISO's Tariffs and Agreements

This Accounting and Billing Manual is intended solely for informational purposes and is subject to change. To the extent that information in this Accounting and Billing Manual is inconsistent with the NYISO's tariffs or agreements, the NYISO's tariffs and agreements shall control.

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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/webdocs/services/financial_services/customer_settlements/initial_settlement_
adj_month_inv_schedule/2010-2011_NYISO_Invoicing_Schedule.pdf

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, Generators, and sub-zone Load meter data provided by Transmission Owners may be updated up to sixty (60) days after the issuance of a service month's initial invoice. Corrections to such 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, and for the NYISO to correct or adjust, errors in their settlement information,, 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, with the exception of metering data, which is limited to challenge and revision within the time frames detailed above.

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. If no implementation errors are identified within the twenty-five–day review period, the NYISO will issue a close-out invoice for the service month. In the event, however, that an error in implementation is identified, the NYISO must correct such error within one month and repost the advisory close-out invoice for an additional twenty-five–day review period. In the event that an error is identified during the second twenty-five–day review period in the NYISO's corrections to the implementation errors identified during the initial twenty-five–day review period, the NYISO shall have one month to correct such errors and then shall issue a close-out invoice.

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:

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

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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 Open Access Transmission Tariff (OATT) and Market Administration and Control Area Services Tariff (Services Tariff or 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.

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.

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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 *Market Participants User's Guide* (*MPUG*) describes the nature of such controls that should be administered by Market Participants to complement the NYISO's controls. The list detailed in the *MPUG* 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 internal controls detailed in the *MPUG* are in place and whether additional controls are warranted.

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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.

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, Transmission Line, and Sub-Zone Load Meter Data Management

Generator, transmission line interconnection, and sub-zone Load meter data are required for settlement of Load Serving Entities' and Generators' Energy and Ancillary Services transactions. The NYISO Open Access Transmission Tariff (OATT) Sections 2.7.4.3.1 and 2.7.4.4.1 and Market Administration and Control Area Services Tariff (Services Tariff) Sections 7.4.2.1 and 7.4.3.1 detail the time periods during which sub-zone Load, 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, Generator, and sub-zone Load

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 and missing hourly sub-zone Load data 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, Generator, and sub-zone Load 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, Generator, and Sub-Zone Load 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, Generator, and sub-zone Load 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, Generator, and sub-zone Load 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 OATT Sections 2.7.4.3.1and 2.7.4.4.1 and Services Tariff Sections 7.4.2.1 and 7.4.3.1 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, or as computed by the respective TOs and submitted to the NYISO, 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, or are computed by the respective TOs and submitted to the NYISO, 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, Generator, and Sub-Zone Load Metering Data Management and Challenges after Invoicing

The NYISO OATT Sections 2.7.4.3.1and 2.7.4.4.1 and Services Tariff Sections 7.4.2.1 and 7.4.3.1 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, Generator, and Sub-Zone Load Metering Data after Invoicing

Submission of challenges to transmission interconnection, Generator, and sub-zone Load 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, Generator, and sub-zone Load hourly metering data.

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, Generator, and sub-zone Load 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, Generator, and sub-zone Load 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, Generator, and sub-zone Load 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, Generator, and sub-zone Load 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.

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, Generator, and sub-zone Load 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, Generator, and sub-zone Load 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 OATT Sections 2.7.4.3.1and 2.7.4.4.1 and Services Tariff Sections 7.4.2.1 and 7.4.3.1 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 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.

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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.

4.1.2 DAM Bid Production Cost Guarantee (BPCG) - Generators

PlaceholderThe NYISO will determine if a Supplier eligible pursuant to Section 4.1.2.1 below for a Day-Ahead Bid Production Cost Guarantee payment will not recover its Day-Ahead Minimum Generation Bid, Start-Up Bid, and Incremental Energy Bid to produce Energy in the Day-Ahead Market through Day-Ahead LBMP revenues and net Day-Ahead Ancillary Services revenues for Voltage Support Service, Regulation Service, and synchronized Operating Reserves. Such determination will be made for an entire Day-Ahead Market day, such determination will be exclusive of any Energy scheduled Day-Ahead to support Bilateral Transactions, and such determination will be made separately for each Generator. On the basis of such determination (and subject to any mitigation that may apply) the NYISO will pay a Day-Ahead BPCG to the Supplier pursuant to the algorithms in Appendix E of this manual.

4.1.2.1 DAM BPCG Eligibility

A Supplier that bids on behalf of a NYISO-Committed Fixed Generator or a NYISO-Committed Flexible Generator that is committed by the NYISO in the Day-Ahead Market (DAM) will be eligible to receive a DAM BPCG payment as long as that Generator has not been committed in the Day-Ahead Market for any other hour of the day as a result of a Self-Committed Fixed or Self-Committed Flexible bid.

A Supplier, otherwise eligible for a DAM BPCG payment, which bids on behalf of a Limited Energy Storage Resource, shall not be eligible to receive a Day-Ahead Bid Production Cost guarantee payment.

4.1.2.2 Formulas for Determining DAM BPCG for Generators

The formulas for determining the DAM BPCG paid to a Supplier depend upon the total MWs of Bilateral Transactions scheduled Day-Ahead sourced by the Generator. The three scenarios illustrated in Appendix E are (a) no Bilateral Transactions; (b) the total MWs of Bilateral Transactions are less than the total MWs of Energy scheduled Day-Ahead; and (c) the total MWs of Bilateral Transactions are greater than or equal to the total MWs of

Energy Scheduled Day-Ahead. Each of the formulas is illustrated in Appendix E of this manual.

4.1.2.2.1 Proration of Start-Up Bid for Generators that are Committed in the Day-Ahead Market, or via Supplemental Resource Evaluation

4.1.2.2.1.1 Eligibility to Recover Operating Costs and Resulting Obligations

Generators committed in the Day-Ahead Market or via Supplemental Resource Evaluation (SRE) that are not able to complete their minimum run time within the Dispatch Day in which they are committed are eligible to include in their Start-Up Bid expected net costs of operating on the day following the Dispatch Day at the minimum operating level specified for the hour in which the Generator is committed, for the hours necessary to complete the Generator's minimum run time.

Generators that receive Day-Ahead or SRE schedules that are not scheduled to operate in real-time, or that do not operate in real-time, at the MW level included in the Minimum Generation Bid for the first hour of the Generator's Day-Ahead or SRE schedule, for the longer of (a) the duration of the Generator's Day-Ahead or SRE schedule or (b) the minimum run time specified in the Bid that was accepted for the first hour of the Generator's Day-Ahead or SRE schedule, will have the start-up cost component of the Bid Production Cost guarantee calculation prorated in accordance with the formula illustrated in Appendix E. The rules for prorating the start-up cost component of the Bid Production Cost guarantee calculation apply both to the operation within the Dispatch Day and to operation on the day following the Dispatch Day to satisfy the minimum run time specified for the hour in which the Generator was scheduled to start-up on the Dispatch Day.

Rules for calculating the reference level that the NYISO uses to test Start-Up Bids for possible mitigation are included in the Market Power Mitigation Measures that are set forth in Attachment H to the NYISO Services Tariff. Proration of the start-up cost component of a Generator's Bid Production Cost guarantee based on the Generator's operation in real-time is different /distinct from the mitigation of a Start-Up Bid.

4.1.2.2.1.2 Proration of Eligible Start-Up Cost when a Generator is Not Scheduled, or Does Not Operate to Meet the Schedule Specified in the Accepted Day-Ahead Start-Up Bid

The start-up costs included in the Bid Production Cost guarantee calculation may be reduced pro rata based on a comparison of the actual MWs delivered in real-time to an hourly minimum MW requirement. The hourly MWh requirement is determined based on the MW component of the Minimum Generation Bid submitted for the Generator's accepted start hour (as mitigated, where appropriate). The proration calculation is illustrated in Appendix E.

4.1.2.3 Day-Ahead BPCG for Demand Side Resources Scheduled to Provide Synchronized Operating Reserves

The NYISO will determine if a Supplier that bids Demand Side Resources committed by the NYISO to provide synchronized Operating Reserves in the Day-Ahead Market will not

recover its Day-Ahead synchronized Operating Reserves Bid to provide the amount of synchronized Operating Reserves that it was scheduled to provide. Such supplier will be eligible under Section 4.1.2.3.1 of this manual for a Day-Ahead Bid Production Cost guarantee payment. Such determination will be made for an entire Day-Ahead Market day, and such determination will be made separately for each Demand Side Resource. On the basis of such determination, the NYISO will make a Bid Production Cost guarantee payment to the Customer pursuant to this Section 4.1.2.3.

4.1.2.3.1 Eligibility for BPCG for Demand Side Resources Providing Synchronized Operating Reserves in the Day-Ahead Market

Any Supplier that bids a Demand Side Resource that is committed by the NYISO to provide synchronized Operating Reserves in the Day-Ahead Market will be eligible to receive a Bid Production Cost guarantee payment under this Section 4.1.2.3.

4.1.2.3.2 Formula for Determining BPCG for Demand Side Resources Providing Synchronized Operating Reserves in the Day-Ahead Market

The formula for determining BPCG for Demand Side Resources providing Synchronized Operating Reserves is detailed in Appendix E of this manual.

4.1.3 Balancing Market Energy Supplier Settlement – Generators

4.1.3.1 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 in which the Generator has offered Energy 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.

4.1.3.2   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.

4.1.3.3   Compensable Overgeneration

Compensable Overgeneration is a quantity of Energy injected by any Generator over a given RTD interval in which the Generator has offered Energy 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, and for Intermittent Power Resources that depend on solar energy or landfill gas for their fuel and that are not bidding in a manner that indicates they are available to provide Regulation Service or Operating Reserves, Compensable Overgeneration is that quantity of Energy injected by the Generator, over a given RTD interval in which the Generator has offered Energy 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.

4.1.3.3.1 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.

4.1.3.4 Energy Settlement – Generators

4.1.3.4.1 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).

4.1.3.4.2 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.

4.1.3.4.3 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 4.1.3, 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.

4.1.4 Real-Time, ~~Balancing Market~~ Bid Production Cost Guarantee for Generators in RTD Intervals Other than Supplemental Event Intervals

The NYISO will determine if a Supplier eligible pursuant to Section 4.1.4.1 below for a real-time Bid Production Cost guarantee payment will not recover its real-time Minimum Generation Bid, Start-Up Bid, and Incremental Energy Bid to produce Energy that was not scheduled in the Day-Ahead Market through real-time LBMP revenues and net real-time Ancillary Services revenues for Voltage Support Service, Regulation Service, and synchronized Operating Reserves. Such determination will be made for an entire Dispatch Day (except for Supplemental Event Intervals). Such determination will be made separately for each Generator. On the basis of such determination, and subject to any mitigation that may apply, the NYISO will pay a real-time Bid Production Cost guarantee payment to the Supplier pursuant to the algorithm in Appendix E of this manual.

4.1.4.1 Eligibilty for Receiving Real-Time BPCG for Generators in RTD Intervals Other Than Supplemental Event intervals

A Supplier will be eligible to receive a real-time Bid Production Cost guarantee payment for intervals (excluding Supplemental Event Intervals) if it bids on behalf of (a) an ISO-

Committed Flexible Generator or an ISO-Committed Fixed Generator that is committed by the NYISO in the Real-Time Market; (b) a Self-Committed Flexible Generator if the Generator's minimum generation MW level does not exceed its Day-Ahead schedule at any point during the Dispatch Day; or (c) a Generator committed via SRE, or committed or dispatched by the NYISO as Out-of-Merit generation to ensure NYCA or local system reliability for the hours of the day that it is committed via SRE or is committed or dispatched by the NYISO as Out-of-Merit generation to meet NYCA or local system reliability without regard to the Bid mode(s) employed during the Dispatch Day.

Suppliers bidding on behalf of Resources that were not committed by the ISO to operate in a given Dispatch Day, but which continue to operate due to minimum run time Constraints, shall not receive such a supplemental payment.

A Supplier, which bids on behalf of a Limited Energy Storage Resource, will not be eligible to receive a real-time Bid Production Cost guarantee payment.

A Supplier that bids on behalf of an ISO-Committed Fixed Generator or an ISO-Committed Flexible Generator that is committed by the NYISO in the real-time market will not be eligible to receive a real-time Bid Production Cost guarantee payment if that Generator has been committed in real-time, in any other hour of the day, as the result of a Self-Committed Fixed bid, or a Self-Committed Flexible bid with a minimum operating level that exceeds its Day-Ahead schedule, *provided however*, a Generator that has been committed in real time as a result of a Self-Committed Fixed bid, or a Self-Committed Flexible bid with a minimum operating level that exceeds its Day-Ahead schedule will not be precluded from receiving a real-time Bid Production Cost guarantee payment for other hours of the Dispatch Day, in which it is otherwise eligible, due to these Self-Committed mode Bids if such bid mode was used for: (i) a NYISO authorized Start-Up, Shutdown or Testing Period, or (ii) for hours in which such Generator was committed via SRE or committed or dispatched by the NYISO as Out-of-Merit to meet NYCA or local system reliability.

4.1.4.2 Formula for Determining Real-Time BPCG for Generators in RTD Intervals Other Than Supplemental Event Intervals

The formula for determining Real-Time BPCG for Generators in RTD intervals other then supplemental event intervals is detailed in Appendix E of this manual.

4.1.4.2.1 Proration of Start-Up Bid for Generators that are Committed in the Day-Ahead Market, or Via Supplemental Resource Evaluation

4.1.4.2.1.1 Eligibility to Recover Operating Costs and Resulting Obligations

Refer to Section 4.1.2.2.2.1 for a description of the eligibility requirements.

4.1.4.2.1.2 Proration of Eligible Start-Up Cost when a Generator is Not Scheduled, or Does Not Operate to Meet the Schedule Specified in the Accepted Day-Ahead or SRE Start-Up Bid

Refer to Section 4.1.2.2.2.2 for a description of the proration requirements.

4.1.4.3 Real-Time BPCG For Demand Side Resources Providing Synchronized Operating Reserves

The NYISO will determine if a Supplier that bids Demand Side Resources committed by the NYISO to provide synchronized Operating Reserves will not recover its real-time synchronized Operating Reserves Bid to provide the amount of synchronized Operating Reserves that it was scheduled to provide. Such Supplier will be eligible under Section 4.1.4.3.1 of this manual for a real-time Bid Production Cost guarantee payment. Such determination will be made for an entire Dispatch Day, and such determination will be made separately for each Demand Side Resource. On the basis of such determination, the NYISO will make a Bid Production Cost guarantee payment to the Customer pursuant to the algorithm described in Appendix E of this manual.

4.1.4.3.1 Eligibility for BPCG for Demand Side Resources Providing Synchronized Operating Reserves in the Real-Time Market

Any Supplier that bids a Demand Side Resource that is committed by the NYISO to provide synchronized Operating Reserves in the Real-Time Market shall be eligible to receive a Bid Production Cost guarantee payment under this Section 4.1.4.3.

4.1.4.3.2 Formula for Determining BPCG for Demand Side Resources Providing Synchronized Operating Reserves in the Real-Time Market

The formula for determining BPCG for Demand Side Resources providing Synchronized Operating Reserves in the Real-Time Market is detailed in Appendix E of this manual.

4.1.5 BPCG for Generators for Supplemental Event Intervals

The NYISO will determine if a Supplier eligible pursuant to Section 4.1.5.1 below for a Bid Production Cost guarantee payment for a Supplemental Event Interval will not recover its real-time Minimum Generation Bid and Incremental Energy Bid to produce Energy that was not scheduled Day-Ahead through real-time LBMP revenues and net real-time Ancillary Services revenues for Voltage Support Service, Regulation Service, and Operating Reserves in that interval. Such determination will be made separately for each Supplemental Event Interval, and such determination will be made separately for each Generator. On the basis of such determination, the NYISO will pay a Bid Production Cost Guarantee payment to the Supplier for a Supplemental Event Interval pursuant to the algorithm in Appendix E of this manual.

4.1.5.1 Eligibility for BPCG for Generators in Supplemental Event Intervals

For intervals in which the NYISO has called a large event reserve pick-up, as described in Section 4.4.4.1.1 of the NYISO Services Tariff, any Supplier who meets the eligibility requirements for a real-time Bid Production Cost guarantee payment described in Section 4.1.4.1 of this manual, will be eligible to receive a BPCG under this Section 4.1.4.

A Supplier will be eligible to receive a Bid Production Cost guarantee payment for a Generator, not a Limited Energy Storage Resource, producing energy during Supplemental

Event Intervals occurring as a result of an ISO emergency under Section 4.4.4.1.2 of the ISO Services Tariff regardless of bid mode used for the day.

Notwithstanding the above, a Supplier will not be eligible to receive a Bid Production Cost guarantee payment for Supplemental Event Intervals if the Supplier is not eligible for a real-time Bid Production Cost guarantee payment for the reasons described in Section 4.1.4 of this manual.

4.1.5.2 *Real-Time BPCG for Generators in Supplemental Event Intervals*

The formula for determining Real-Time BPCG for Generators in Supplemental Event Intervals is detailed in Appendix E of this manual.

4.1.6 BPCG for Long Start-Up Time Generators Whose Starts Are Aborted by the NYISO Prior to their Dispatch

The NYISO will pay a Supplier eligible under Section 4.1.6.1 of this manual for a Bid Production Cost guarantee payment for a long start-up time Generator (i.e., a Generator that cannot be scheduled by SCUC to start up in time for the next Dispatch Day) whose start is aborted by the NYISO prior to its dispatch of that portion of its Start-Up Bid that corresponds to that portion of its start-up sequence that it completed prior to being aborted. Such determination will be made for an entire Dispatch Day, and such determination will be made separately for each long start-up time Generator. On the basis of such determination, the NYISO will pay a Bid Production Cost guarantee payment to the Supplier pursuant to the methodology described in Section 4.1.6.2 below.

4.1.6.1 *Eligibility for BPCG for Long Start-Up Time Generators Whose Starts Are Aborted by the NYISO Prior to their Dispatch*

A Supplier that bids on behalf of a long start-up time Generator (i.e., a Generator that cannot be scheduled by SCUC to start up in time for the next Dispatch Day) that is committed by the NYISO for reliability purposes as a result of a Supplemental Resource Evaluation and whose start is aborted by the NYISO prior to its dispatch, as described in Section 4.2.5 of the NYISO Services Tariff, will be eligible to receive a Bid Production Cost guarantee payment under this Section 4.1.6.

4.1.6.2 *Methodology for Determining BPCG for Long Start-Up Time Generators Whose Starts are Aborted by the NYISO Prior to their Dispatch*

A Supplier whose long start-up time Generator's start-up is aborted shall receive a prorated portion of its Start-Up Bid submitted for the hour in which the NYISO requested that the Generator begin its start-up sequence, based on the portion of the start-up sequence that it has completed prior to the signal to abort the start-up (e.g., if a long start-up time Generator with a seventy-two (72) hour start-up time has its start-up sequence aborted after forty-eight (48) hours, it would receive two-thirds (2/3) of its Start-Up Bid).

Placeholder

4.1.54.1.7   Day-Ahead Margin Assurance Payments (DAMAP)

If a Supplier that that is eligible pursuant to Section 4.1.56.1 below buys out of a Day-Ahead Energy, Regulation Service, or Operating Reserve schedule in a manner that reduces its Day-Ahead Margin, it will receive a Day-Ahead Margin Assurance Payment (DAMAP), with the potential exceptions of Generators that lag behind their real-time Base Point Signals and Suppliers that have been derated. The purpose of such payments is to protect Suppliers' Day-Ahead Margins associated with real-time reductions after accounting for: (i) any real-time profits associated with offsetting increases in real-time Energy, Regulation Service, or Operating Reserve Schedules; and (ii) any Supplier requested real-time derate granted by the NYISO.

4.1.5.14.1.7.1   DAMAP Eligibility

The following categories of Suppliers are eligible to receive DAMAP: (i) all Self-Committed Flexible and NYISO-Committed Flexible Generators that are online and dispatched by RTD; (ii) Demand Side Resources committed to provide Operating Reserves or Regulation Service; (iii) any Supplier that is scheduled out of economic merit order by the NYISO in response to a NYISO or Transmission Owner system security need or to permit the NYISO to procure additional Operating Reserves; (iv) any Supplier internal to the NYCA that is derated or decommitted by the NYISO in response to a NYISO or Transmission Owner system security need or to permit the NYISO to procure additional Operating Reserves; and (v) Energy Limited Resources with a NYISO-approved real-time reduction in output from its Day-Ahead schedule.

No DAMAP is paid to a Supplier, otherwise eligible for a DAMAP, in hours in which the NYISO has increased the Supplier's minimum operating level, either: (i) at the Generator's request; or (ii) in order to reconcile the NYISO's dispatch with the Generator's actual output or to address reliability concerns that arise because the Generator is not following Base Point Signals. In addition, no DAMAP is paid to an Intermittent Power Resource that depends on wind as its fuel.

In addition, no DAMAP is paid to a Generator otherwise eligible for a DAMAP for: (i) any hour in which Incremental Energy Bids submitted in the Real-Time Market for that Generator exceed the Incremental Energy Bids submitted in the Day-Ahead Market, or the mitigated Day-Ahead Incremental Energy Bids, where appropriate, for the portion of that Generator's Capacity that was scheduled in the Day-Ahead Market; and (ii) the two hours immediately preceding and the two hours immediately following the hour(s) identified in (i).

If an otherwise eligible Generator's average Actual Energy Injection in an RTD interval (i.e., its Actual Energy Injections averaged over the RTD interval) is less than or equal to its penalty limit for under-generation value for that interval, the Generator is not eligible for DAMAP for that interval. The calculation of a Generator's penalty limit for undergeneration (PLU) is detailed in Appendix G of this manual.

~~4.1.5.2~~4.1.7.2 DAMAP to Generators

The hourly DAMAP paid to eligible Generators is computed as the greater of zero and the sum of (a) the hourly integrated RTD interval DAMAP associated with the Generator's supply of Energy over the subject hour; (b) the hourly integrated RTD interval DAMAP associated with the Generator's supply of Regulation Service over the subject hour; and (c) the hourly integrated RTD interval DAMAP associated with the Generator's supply of Operating Reserves summed for each Operating Reserves product over the subject hour.

The determination of eligible Generators' DAMAP is illustrated formulaically in Appendix H of this manual.

~~4.1.5.2.1~~4.1.7.2.1 Energy Component of DAMAP Due to Generator

The DAMAP paid to a Supplier based on its Energy schedule is determined as follows at the RTD interval level and is integrated and summed over the hour. In the event of a Generator derate, the DAM Energy schedule used in the equations detailed in this section will be reduced as described below in Section 4.1.~~5~~6.2.6.

Real-Time Energy Schedule < DAM Energy Schedule

If the eligible Generator's real-time Energy schedule is lower than its DAM Energy schedule, the DAMAP paid for the Generator's Energy schedule for each RTD interval is computed as (a) the product of (i) the real-time LBMP at the Generator's bus and (ii) the difference between (A) the Generator's DAM Energy schedule and (B) the Generator's RTD Energy schedule, as adjusted according to the Generator's Actual Energy Injection and Economic Operating Point as described in the following paragraph, minus (b) the Generator's DAM Energy bid for the hour.

The Generator's RTD Energy schedule used in the previous paragraph will be adjusted as follows. When the Generator's RTD Energy schedule is less than the Generator's Economic Operating Point over the RTD interval, the Generator's RTD Energy schedule over the RTD interval is adjusted to the lesser of (a) the Generator's DAM Energy schedule and (b) the greater of (i) its RTD Energy schedule over the RTD interval and (ii) the lesser of (A) the Generator's Actual Energy Injection over the RTD interval and (B) the Generator's Economic Operating Point over the RTD interval. In all other cases, the Generator's RTD Energy schedule is adjusted to the lesser of (a) its DAM Energy schedule and (b) the lesser of (i) the Generator's RTD Energy schedule over the RTD interval and (ii) the greater of: (a) the Generator's Actual Energy Injection over the RTD interval and (B) the Generator's Economic Operating Point over the RTD interval.

Real-Time Energy Schedule ≥ DAM Energy Schedule

If the eligible Generator's real-time Energy schedule is greater than or equal to its DAM Energy schedule, the DAMAP paid for the Generator's Energy schedule for each RTD interval is computed as the lesser of zero and (a) the product of (i) the real-time LBMP at the Generator's bus and (ii) the difference between the Generator's DAM Energy schedule and the Generator's RTD Energy schedule, as adjusted according to the Generator's Actual Energy Injection and Economic Operating Point as described in the following paragraph, plus (b) the Generator's real-time Energy bid for the hour for the incremental Energy scheduled above its DAM schedule.

The Generator's RTD Energy schedule used in the previous paragraph will be adjusted as follows. When the Generator's RTD Energy schedule over the RTD interval is greater than or equal to its Economic Operating Point over the RTD interval at the same time that the Generator's Economic Operating Point over the RTD interval is greater than or equal to the Generator's DAM Energy schedule, the Generator's RTD Energy schedule over the RTD interval is adjusted to the greater of (a) the Generator's DAM Energy schedule and (b) the lesser of (i) the Generator's RTD Energy schedule over the RTD interval and (ii) the greater of (A) the Generator's Actual Energy Injection over the RTD interval and (B) the Generator's Economic Operating Point over the RTD interval. When the eligible Generator's real-time Energy schedule over the RTD interval is greater than its DAM Energy schedule, the Generator's RTD Energy schedule over the RTD interval is adjusted to the greater of (a) its DAM Energy schedule and (b) the greater of (i) the Generator's RTD Energy schedule over the RTD interval and (ii) the lesser of (C) the Generator's Actual Energy Injection over the RTD interval and (D) the Generator's Economic Operating Point over the RTD interval.

4.1.5.2.24.1.7.2.2 Energy Component of DAMAP Due to Energy Limited Resources

For any day in which (i) an Energy Limited Resource is scheduled to supply Energy, Operating Reserve Service or Regulation Service in the Day-Ahead Market; (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 NYISO modifies the Energy Limited Resource's Day-Ahead upper operating limit; the imbalance charge imposed upon the Energy Limited Resource is computed as the product of (a) the sum of its Energy, Operating Reserve Service and Regulation Service imbalances across all twenty-four hours of the Energy day and (b) the real-time price for each service in each hour at its location. If the total margin received by the Energy Limited Resource for the twenty-four hour day is less than its Day-Ahead margin, then the Generator will receive a DAMAP.

4.1.5.2.34.1.7.2.3 Regulation Component of DAMAP Due to Generator

The DAMAP paid to a Supplier based on its Regulation Service schedule is determined as follows at the RTD interval level and is integrated and summed over the hour. In the event of a Generator derate, the DAM Regulation Service schedule used in the equations detailed in this section will be reduced as described below in Section 4.1.56.2.6. The determination of the Regulation Service component of DAMAP due to eligible Generators is illustrated formulaically in Appendix H of this manual.

Real-Time Regulation Schedule < DAM Regulation Service Schedule

If the eligible Generator's real-time Regulation Service schedule over the RTD interval is lower than its DAM Regulation Service schedule, the DAMAP paid for the Generator's Regulation Service schedule for each RTD interval is computed as the product of (a) the Generator's DAM Regulation Service schedule for the hour containing that RTD interval minus the Generator's real-time Regulation Service schedule in that RTD interval and (b) the real-time Market Clearing Price for Regulation Service in that RTD interval minus the

Generator's DAM bid to supply Regulation Service for the hour containing that RTD interval.

Real-Time Regulation Service Schedule ≥ DAM Regulation Service Schedule

If the eligible Generator's real-time Regulation Service schedule over the RTD interval is greater than or equal to its DAM Regulation Service schedule, the DAMAP paid for the Generator's Regulation Service schedule for each RTD interval is computed as the product of (a) the Generator's DAM Regulation Service schedule for the hour containing that RTD interval minus the Generator's real-time Regulation Service schedule over the RTD interval and (b) the greater of (i) zero and (ii) the real-time Market Clearing Price for Regulation Service in that RTD interval minus the Generator's real-time bid to supply Regulation Service for the hour containing that RTD interval.

~~4.1.5.2.4~~4.1.7.2.4 Operating Reserve Component of DAMAP Due to Generator

The DAMAP paid to a Supplier based on its Operating Reserve Service schedule for each product p of Operating Reserve scheduled is determined as follows at the RTD interval level and is integrated and summed over the hour. In the event of a Generator derate, the DAM Operating Reserves Service schedule used in the equations detailed in this section will be reduced as described below in Section 4.1.~~5~~6.2.6. The determination of the Operating Reserve component of DAMAP due to eligible Generators is illustrated formulaically in Appendix H of this manual.

Real-Time Operating Reserve Schedule < DAM Operating Reserve Schedule

If the eligible Generator's real-time Operating Reserve schedule for Operating Reserve product p is lower than its DAM Operating Reserve schedule for Operating Reserve product p, the DAMAP paid for the Generator's Operating Reserve schedule for Operating Reserve product p for each RTD interval is computed as the product of (a) the Generator's DAM Operating Reserve schedule for Operating Reserve product p for the hour containing that RTD interval minus the Generator's real-time Operating Reserve schedule for Operating Reserve product p in that RTD interval and (b) the real-time Market Clearing Price for Operating Reserve product p in that RTD interval minus the Generator's DAM bid to supply Operating Reserve for Operating Reserve product p for the hour containing that RTD interval.

Real-Time Operating Reserve Schedule ≥ DAM Operating Reserve Schedule

If the eligible Generator's real-time Operating Reserve schedule for Operating Reserve product p is greater than or equal to its DAM Operating Reserves Service schedule for Operating Reserve product p, the DAMAP paid for the Generator's Operating Reserve schedule for Operating Reserve product p for each RTD interval is computed as the product of (a) the Generator's DAM Operating Reserves schedule for Operating Reserve product p for the hour containing that RTD interval minus the Generator's real-time Operating Reserve schedule for Operating Reserve product p in that RTD interval and (b) the real-time Market Clearing Price for Operating Reserve product p in that RTD interval.

~~4.1.5.2.5~~4.1.7.2.5 DAMAP Due to Limited Energy Storage Resources

DAMAP for Limited Energy Storage Resources (LESR) scheduled to provide Regulation Service is payable only for intervals in which the NYISO has reduced the real-time Regulation Service offer (in megawatts) of a LESR and the NYISO is not pursuing LESR Energy Management for such Resource for such interval. The determination of DAMAP due to an eligible LESR is illustrated formulaically in Appendix H of this manual.

Real-Time Regulation Service Schedule < DAM Regulation Service Schedule

If the LESR's real-time Regulation Service schedule is less than its DAM Regulation Service schedule in the hour containing the RTD interval, then the DAMAP paid for the Resource's Regulation schedule is computed as the product of (a) the Generator's DAM Regulation Service schedule for the hour containing that RTD interval minus its real-time Regulation Service schedule in that RTD interval; (b) the real-time Market Clearing Price for Regulation Service in that RTD interval minus the Generator's DAM bid to supply Regulation Service for the hour containing that RTD interval; and (c) the LESR's Performance Index over the RTD interval. The calculation of the Performance Index is described in Appendix G of this manual.

Real-Time Regulation Service Schedule ≥ DAM Regulation Service Schedule

If the LESR's real-time Regulation Service schedule is greater than or equal to its DAM Regulation Service schedule in the hour containing the RTD interval, then the DAMAP paid for the Resource's Regulation schedule is computed as the product of (a) the Generator's DAM Regulation Service schedule for the hour containing that RTD interval minus its real-time Regulation Service schedule in that RTD interval and (b) the greater of (i) zero and (ii) the real-time Market Clearing Price for Regulation Service in that RTD interval minus the Generator's real-time bid to supply Regulation Service for the hour containing that RTD interval.

~~4.1.5.2.6~~4.1.7.2.6 Adjustments to DAMAP Resulting from Generator Derates

Suppliers that request and are granted a derate of their real-time Operating Capacity, but are otherwise eligible to receive DAMAP, may receive a payment up to a Capacity level consistent with their revised Emergency Upper Operating Limit or Normal Upper Operating Limit, whichever is applicable. The foregoing rule is also applied to a Generator, otherwise eligible for a DAMAP, in hours in which the NYISO has derated the Generator's Operating Capacity in order to reconcile the NYISO's dispatch with the Generator's actual output, or to address reliability concerns that arise because the Generator is not following Base Point Signals.

If a Supplier's derated real-time Operating Capacity is lower than the sum of its DAM Energy, Regulation Services, and Operating Reserve schedules, the Generator's DAM schedules for Energy, Regulation Service, and Operating Reserves Service used to compute the Generator's DAMAP will be reduced respectively when applied to the settlement rules described above. The reductions to an eligible Generator's DAM Energy, Regulation Service, and Operating Reserves Service schedules in computing the Generator's DAMAP, described above, are illustrated formulaically in Appendix H of this manual.

~~4.1.5.3~~4.1.7.3 DAMAP to Demand Side Resources Scheduled to Provide Regulation Service and Operating Reserves Service

The hourly DAMAP for Demand Side resources scheduled to provide Regulation Service and Operating Reserves for each respective Operating Reserve product p is computed at the RTD interval level and is integrated and summed over the hour. The hourly DAMAP for Demand Side resources scheduled to provide Regulation Service and Operating Reserves for each respective Operating Reserve product p is computed as the greater of (a) zero and (b) the sum of the Regulation Service DAMAP and Operating Reserve DAMAP for each respective Operating Reserve product p due to the Resource over the hour, as described below in Sections 4.1.~~5~~6.3.1 and 4.1.~~5~~6.3.2, respectively, and as illustrated formulaically in Appendix H of this manual.

~~4.1.5.3.1~~4.1.7.3.1 Regulation Service Component of DAMAP Due to Demand Side Resources

The DAMAP paid to a Demand Side Resource based on its Regulation Service schedule is determined as follows at the RTD interval level and is integrated and summed over the hour.

Real-Time Regulation Schedule < DAM Regulation Service Schedule

If the Demand Side Resource's real-time Regulation Service schedule is less than its Day-Ahead Regulation Service schedule, then the DAMAP paid for the Demand Side Resource's Regulation Service schedule for each RTD interval is computed as the product of (a) the Resource's DAM Regulation Service schedule for the hour containing that RTD interval minus the Resource's real-time Regulation Service schedule in that RTD interval and (b) the real-time Market Clearing Price for Regulation Service in that RTD interval minus the Resource's DAM bid to supply Regulation Service for the hour containing that RTD interval.

Real-Time Regulation Service Schedule ≥ DAM Regulation Service Schedule

If the Demand Side Resource's real-time Regulation Service schedule is greater than or equal to its DAM Regulation Service schedule, then the DAMAP paid for the Demand Side Resource's Regulation Service schedule for each RTD interval is computed as the product of (a) the Resource's DAM Regulation Service schedule for the hour containing that RTD interval minus the Resource's real-time Regulation Service schedule in that RTD interval and (b) the greater of (i) zero and (ii) the real-time Market Clearing Price for Regulation Service in that RTD interval minus the Resource's real-time bid to supply Regulation Service for the hour containing that RTD interval

~~4.1.5.3.2~~4.1.7.3.2 Operating Reserve Component of DAMAP Due to Demand Side Resources

The DAMAP paid to a Demand Side Resource based on its Operating Reserve schedules is determined as follows:

Real-Time Operating Reserve Schedule < DAM Operating Reserve Schedule

If the Demand Side Resource's real-time schedule for a given Operating Reserve product *p* is less than its Day-Ahead Operating Reserve schedule for Operating Reserve product "p, then the DAMAP paid for the Demand Side Resource's Operating Reserve schedule for Operating Reserve product *p* for each RTD interval is computed as the product of (a) the Resource's DAM Operating Reserves Service schedule for the hour containing that RTD interval minus the Resource's real-time Operating Reserves Service schedule in that RTD interval; (b) the real-time Market Clearing Price for Operating Reserves Service in that RTD interval minus the Resource's DAM bid to supply Operating Reserves Service for the hour containing that RTD interval; and (c) the Reserves Performance Index computed for the Demand Side Resource in the RTD interval, as described in section in Section 4.1.5.3.3, below.

Real-Time Operating Reserve Schedule ≥ DAM Operating Reserve Schedule

If the Demand Side Resource's real-time schedule for Operating Reserve product *p* is greater than or equal to its Day-Ahead Operating Reserve schedule for Operating Reserve product *p*, then the DAMAP paid for the Demand Side Resource's Operating Reserve schedule for Operating Reserve product *p* for each RTD interval is computed as the product of (a) the Resource's DAM Operating Reserves Service schedule for the hour containing that RTD interval minus the Resource's real-time Operating Reserves Service schedule in that RTD interval; (b) the real-time Market Clearing Price for Operating Reserves Service in that RTD interval; and (c) the Reserve Performance Index computed for the Demand Side Resource in the RTD interval, as described in section in Section 4.1.~~5~~6.3.3, below.

~~4.1.5.3.3~~4.1.7.3.3 Reserve Performance Index for Demand Side Resource Suppliers of Operating Reserves

A Reserve Performance Index (RPI) is computed by the NYISO for the purpose of calculating the DAMAP for Demand Side Resources scheduled to provide Operating Reserves in the Day-Ahead Market. The RPI takes into account the actual Demand Reduction achieved by the Supplier of Operating Reserves following the NYISO's instruction to convert Operating Reserves to Demand Reduction.

The RPI 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 convert its Operating Reserves to Demand Reduction, the Resource's RPI is set to 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 RPI is calculated as the greater of (a) zero and (b) the lesser of (i) one and (ii) the sum of (A) one-tenth and (B) the quotient of (c) the Average Actual Demand Reduction measured from the Resource over the RTD interval and (d) the Average scheduled Demand Reduction measured for the Resource over the RTD interval. In the event that the Average Actual Demand Reduction measured from the Demand Side Resource over the RTD interval zero or less, the RPI is set to zero.

The determination of a Demand Side Resource's RPI is illustrated formulaically in Appendix G of this manual.

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.

4.2.2 BPCG for Demand Reduction in the Day-Ahead Market

~~4.2.1.1 DAM Bid Production Cost Guarantee Payment~~

~~Placeholder~~The NYISO will determine if a Demand Reduction Provider eligible under Section 4.2.2.1 of this manual for a Bid Production Cost guarantee payment for Demand Reduction in the Day-Ahead Market will not recover its Day-Ahead Curtailment Initiation Cost and its Day-Ahead Demand Reduction Bid through Day-Ahead LBMP revenues. Such determination will be made for an entire Day-Ahead Market day, and such determination will be made separately for each Demand Side Resource. On the basis of such determination, the NYISO will pay a Bid Production Cost guarantee payment to the Demand Reduction Provider pursuant to the algorithms described in Appendix E.

4.2.2.1 Eligibilty for BPCG for Demand Reduction in the Day-Ahead Market

A Demand Reduction Provider that bids a Demand Side Resource that is committed by the NYISO in the Day-Ahead Market to provide Demand Reduction will be eligible to receive a Bid Production Cost guarantee payment under this Section 4.2.2.

4.2.2.2 Formula for BPCG for Demand Reduction in the Day-Ahead Market

The formula for determining BPCG for Demand Reduction in the Day-Ahead Market is detailed in Appendix E of this manual.

4.2.24.2.3 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).

4.2.2.14.2.3.1 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   Day-Ahead BPCG for Imports

The NYISO will determine if a Supplier supplying an Import Sale to the LBMP Market and eligible under Section 4.3.2.1 of this manual for a Day-Ahead Bid Production Cost guarantee payment will not recover its Day-Ahead Decremental Bid through Day-Ahead LBMP revenues. Such determination will be made for an entire Day-Ahead Market day and such determination will be made separately for each Import transaction. On the basis of such determination, the NYISO will pay a Day-Ahead Bid Production Cost guarantee payment to the Supplier pursuant to the algorithm in Appendix E.

4.3.2.1   Eligibility to Receive a Day-Ahead BPCG for Imports

A Supplier that bids an Import sale to the LBMP Market that is committed by the NYISO in the Day-Ahead Market will be eligible to receive a Day-Ahead Bid Production Cost guarantee payment.

4.3.2.2   BPCG Calculated by Transaction ID

For purposes of calculating a Day-Ahead Bid Production Cost guarantee payment for an Import under this Section 4.3.2, the NYISO will treat the Import as being from a single Resource for all hours of the Day-Ahead Market day in which the same Transaction ID is used, and the NYISO will treat the Import as being from a different Resource for all hours of the Day-Ahead Market day in which a different Transaction ID is used.

4.3.2.3   Formula for Day-Ahead BPCG for Imports

The formula for determining Day-Ahead BPCG for Imports is detailed in Appendix E of this manual.

~~4.3.2~~4.3.3   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~~D~~ in each ~~hour~~RTD interval, minus the amount of Energy scheduled Day-Ahead for the External Generator in that hour~~.~~, in megawatt hours; and (b) the ~~Real-Time~~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~~LBMP from the RTD LBMP in the relevant RTD intervals. The RTC LBMP is the LBMP used to schedule the transaction. For hourly transactions, it is the 3rd, 4th, 5th and 6th LBMPs out of the RTC_{15} evaluation. For intra-hourly transactions, it is the LBMP from the rolling RTC that scheduled the transaction.

The Financial Impact Charge settlement for LBMP Energy Import Transactions failing the NYISO checkout process is illustrated formulaically in Appendix B.

4.3.4   Real-Time BPCG for Imports

The NYISO will determine if a Supplier supplying an Import sale to the LBMP Market and eligible pursuant to Section 4.3.4.1 below for a real-time Bid Production Cost guarantee payment will not recover its real-time Decremental Bid through real-time LBMP revenues. Such determination will be made for an entire Dispatch Day. Such determination will be made separately for each Import transaction. On the basis of such determination, the NYISO will pay a real-time Bid Production Cost guarantee payment to the Supplier pursuant to the algorithm described in Appendix E

4.3.4.1   Eligibilty for Receiving Real-Time BPCG for Imports

A Supplier that bids an Import to sell Energy to the LBMP Market that is committed by the NYISO in the Real-Time Market will be eligible to receive a real-time Bid Production Cost guarantee payment for all intervals.

Notwithstanding the above:

Customers that schedule hourly Import Transactions at either Variably Scheduled Proxy Generator Buses or Dynamically Scheduled Proxy Generator Buses will not be eligible for Real-Time shortfall payments for those Transactions for the day.

When a Non-Competitive Proxy Generator Bus or the Interface between the NYCA and the Control Area in which the Non-Competitive Proxy Generator Bus is located is export constrained due to limits on available Interface Capacity or Ramp Capacity limits for that Interface in an hour, Customers scheduling an Import at such Non-Competitive Proxy Generator Bus in that hour shall not be eligible for a real-time Bid Production Cost guarantee payment for this Transaction.

When a Proxy Generator Bus that is associated with a designated Scheduled Line is export constrained due to limits on available Interface Capacity in an hour, Customers scheduling an Import at such Proxy Generator Bus in that hour will not be eligible for a real-time Bid Production Cost guarantee payment for this Transaction.

When the Rolling RTC is export constrained due to limits on NYCA Ramp Capacity in an hour, Customers scheduling Imports at Proxy Generator Buses associated with designated Scheduled Lines and Non-Competitive Proxy

Generator Buses in that hour will not be eligible for real-time shortfall payments for those Transactions.

4.3.4.2   BPCG Calculated by Transaction ID

For purposes of calculating a real-time Bid Production Cost guarantee payment for an Import under this Section 4.3.4, the NYISO will treat the Import as being from a single Resource for all hours of the Dispatch Day in which the same Transaction ID is used, and the NYISO will treat the Import as being from a different Resource for all hours of the Dispatch day in which a different Transaction ID is used.

4.3.4.3   Formula for Real-Time BPCG for Imports

The formula for determining Real-Time BPCG for Imports is detailed in Appendix E of this manual.

4.3.5   Import Curtailment Guarantee Payments

4.3.5.1   Eligibility for an Import Curtailment Guarantee Payment for an Import Curtailed by the NYISO

In the event that the Energy injections for an Import scheduled by RTC or RTD at a Proxy Generator Bus are Curtailed at the request of the NYISO, and (i) the real-time Energy Profile MW is equal to or greater than the Day-Ahead Energy Schedule for that interval, and (ii) the real-time Decremental Bid is less than or equal to the default real-time Decremental Bid amount as established by ISO procedures, then the Supplier or Transmission Customer that is subjected to the Curtailment, in addition to the charge for Energy Imbalance, shall be eligible for an Import Curtailment Guarantee Payment as described by the algorithm in Appendix E

4.3.5.2   Formula for an Import Curtailment Guarantee Payment for an Import Curtailed by the NYISO

The formula for determining an Import Curtailment Guarantee Payment for an Import Curtailed by the NYISO is detailed in Appendix E of the manual.

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 megawatt hours 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 megawatt hours. Each Curtailment Service Provider is paid the zonal Real-Time LBMP per megawatt hour 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.

4.5.1 BPCG for Special Case Resources

The NYISO will determine if a Supplier eligible under Section 4.5.1.1 of this manual for a Bid Production Cost guarantee payment for a Special Case Resource will not recover its Minimum Payment Nomination through real-time LBMP revenues. Such determination will

be made for an entire Dispatch Day, and such determination will be made separately for each Special Case Resource. On the basis of such determination, the NYISO will make a Bid Production Cost guarantee payment to the Supplier pursuant to the methodology in Section 4.5.1.2 of this manual.

4.5.1.1 Eligibility for Special Case Resources BPCG

Any Supplier that bids a Special Case Resource that is committed by the NYISO for an event in the Real-Time Market will be eligible to receive a Bid Production Cost guarantee payment under this Section 4.5.1. Suppliers will not be eligible for a Special Case Resource Bid Production Cost guarantee payment for the period over which a Special Case Resource is performing a test.

4.5.1.2 Methodology for Determining Special Case Resources BPCG

A Special Case Resource Bid Production Cost guarantee payment will be made when the Minimum Payment Nomination for any Special Case Resource committed by the NYISO over the period of requested performance or four (4) hours, whichever is greater, exceeds the LBMP revenue received for performance by that Special Case Resource; provided, however, that the NYISO will set to zero the Minimum Payment Nomination for Special Case Resource Capacity in each interval in which such capacity was scheduled Day-Ahead to provide Operating Reserves, Regulation Service or Energy.

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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 (Section 15.2) of the NYISO Services Tariff, 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 (Section 15.2) of the Services Tariff 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 (Section 5) of the NYISO Services Tariff, 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.

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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 that depend on wind as their fuel and Limited Control Run of 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;

- Intermittent Power Resources that depend on solar energy or landfill gas as their fuel;

- 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 Shut down 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)

6.1.1 DAM Energy Settlement – LSEs

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).

The LSE DAM Energy settlement is illustrated formulaically in Appendix J.

6.1.2 Balancing Market Energy Settlement – LSEs

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.

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

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, 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.

The LSE Balancing Market Energy settlement is illustrated formulaically in Appendix J.

6.2 Energy Settlement – LBMP Energy Exports

6.2.1 DAM Energy Settlement – LBMP Energy Exports

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.

The DAM LBMP Energy Export settlement is illustrated formulaically in Appendix J.

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~~ RTD 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.

The Balancing Market LBMP Energy Export settlement is illustrated formulaically in Appendix J.

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 NYISO's Market Monitoring and Performance UnitMitigation and Analysis Department 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 priceLBMP in the relevant interval from the RTC LBMP price, or zero. The RTC LBMP is the LBMP used to schedule the transaction. For hourly transactions, it is the 3rd, 4th, 5th and 6th LBMPs out of the RTC_{15} evaluation. For intra-hourly transactions, it is the LBMP from the rolling RTC that scheduled the transaction.

The Financial Impact Charge settlement for LBMP Energy Export Transactions failing the NYISO checkout process is illustrated formulaically in Appendix J.

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.

The DAM Energy settlement for Virtual Load is illustrated formulaically in Appendix J.

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.

The Balancing Market Energy settlement for Virtual Load is illustrated formulaically in Appendix J.

6.4 Energy Settlement – Station Power

Station Power is the energy used by a Generator to operate electrical equipment and for the incidental heating, lighting, air conditioning, and office equipment needs of buildings, or portions thereof, that are: (a) owned by the same entity that owns the Generator; (b) located on the Generator site; and (c) used by the Generator exclusively for the production of Energy and any useful thermal energy associated with the production of Energy. Station Power does not include any Energy: (i) used to power synchronous condensers; (ii) used for pumping at a pumped storage facility or for charging a Limited Energy Storage Resource; or (iii) provided during a Black Start restoration by Generators that provide Black Start Capability Service. Station Power may be procured in three ways: Self-Supply, Remote Self-Supply, and Third Party Supply.

Station Power settlements are illustrated by example in Appendix N.

6.4.1 Self-Supply Station Power

A Generator may self-supply Station Power during any calendar month when either: (i) its net output for that month is positive; or (ii) its net output for that month is negative and the Generator, during the same month, has available at other Generators owned by the same entity that owns the Generator positive net output in an amount at least sufficient to offset fully such negative net output (hereinafter referred to as "remote self-supply of Station Power"). A Generator may not remotely self-supply Station Power from Generators that are owned by its owner's corporate affiliates.

Self-Supply of Station Service is accomplished by the netting of generation output against station service load over a monthly period for the same unit or complex of units associated with the same Corporate Entity (CE). Since all netting occurs within the footprint of the generation facility, no charges are assessed.

When a Generator has positive net output for an interval and is delivering Energy into the New York State Power System, it will be paid the Real-Time or Day-Ahead LBMP at its bus, as appropriate, for all of the Energy delivered pursuant to the NYISO Services Tariff. Conversely, when a Generator has negative net output for an interval and is self-supplying Station Power from the New York State Power System as described in Sections 6.4.2, 6.4.3, and Appendix N, herein, it will pay the Real-Time or Day-Ahead LBMP, as appropriate, for all of the Energy consumed, pursuant to the NYISO Services Tariff. When a Generator self-supplies Station Power during any month the Generator will not incur any charges for Transmission Service.

6.4.2 Third-Party Station Power

In the event that the monthly net of generation output for a CE is negative, then Third-Party Station Power occurred. In addition, some Remote Self-Supply Station Power may have occurred, as well. Third-Party Station Service is determined by computing the remaining station service load after Self-Supplied and Remote Self-Supplied Station Service have been netted against such station service load, over a monthly period for units by the same CE.

For CEs that have a negative monthly net generation, the absolute value of that negative monthly amount, or Third-Party Station Power, is allocated across all units of the CE having net negative outputs for the month, by allocating such Station Power against the units with the largest net negative values first, until all Third-Party Station Power has been allocated.

For each unit having Third-Party Station Power allocations, the wholesale cost of such Third-Party Station Power is determined by multiplying: (i) the hourly integrated LBMP at the generator's bus by (ii) hourly net negative generation value and the unit's allocation of Third-Party Supply and then dividing by the total of all hourly negative values for the month. These costs are aggregated over the month and charged to the respective LSE. The Generator(s) are paid a rebate equivalent to this wholesale cost. This calculation is detailed in Appendix N.

6.4.3 Remote Self-Supply Station Power

Remote Self-Supply of Station Service is accomplished by the netting of remotely located generation output against remaining station service load, after Self-Supplied Station Service has been netted against such station service load, over a monthly period for units by the same CE. Generators having Remote Self-Supply Station Service are assessed NTAC for all megawatt hours of Self-Supply.

When a Generator remotely self-supplies Station Power, the Generator will, to the extent that Transmission Service is involved, pay for Transmission Service for the quantity of Energy that the Generator remotely self supplies. Such Transmission Service will be provided under Section 3 of the NYISO OATT and will be charged the hourly rate under Schedule 7 (Section 6.7) of the NYISO OATT for firm Point-to-Point Transmission Service, provided however, that the terms and charges under Schedules 1 (Section 6.1) through 3 (Section 6.3), 5 (Section 6.5), 6 (Section 6.6), 8 (Section 6.8), and 9 (Section 6.9) of the NYISO OATT shall not apply to such service.

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7. TRANSMISSION USAGE CHARGE (TUC) AND TRADING HUB ENERGY SETTLEMENTS

7.1 TUC Settlements – Internal Transactions

7.1.1 DAM TUC Settlements – Internal Transactions

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 megawatt hours; 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 megawatt hours, 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.

DAM TUC settlements for Internal Transactions are described formulaically in Appendix K.

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 (megawatt hours) purchased in the LBMP Market.

DAM replacement Energy settlements for Generators designated as the Suppliers of Energy for Bilateral Transactions that are scheduled to produce less Energy than is necessary to support the Internal Transactions are described formulaically in Appendix B.

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 megawatt hours; 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 megawatt hours; 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.

Balancing Market TUC settlements for Internal Transactions are described formulaically in Appendix K.

7.1.2.1   Real-Time Replacement Energy to Support Internal Transactions

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 megawatt hours) necessary to supply the Transaction.

Real-Time replacement Energy settlements for Generators designated as the Suppliers of Energy for that Bilateral Transactions that are dispatched in real-time to produce less Energy than necessary to supply the Transactions are described formulaically in Appendix B.

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

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; and (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. 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.

7.2   TUC Settlements – Import Bilateral Transactions

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 megawatt hours; 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.

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 megawatt hours, 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.

DAM TUC settlements for Import Bilateral Transactions are described formulaically in Appendix K.

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 (megawatt hours) 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.

DAM replacement Energy settlements for Curtailed Import Transactions are described formulaically in Appendix K.

7.2.2 Balancing Market TUC Settlements – Import Bilateral Transactions

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 megawatt hours; 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.

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 megawatt hours; 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.

Balancing Market TUC settlements for Import Bilateral Transactions are described formulaically in Appendix K.

7.2.2.1   Real-Time Replacement Energy for Curtailed Imports

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 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 (megawatt hours) 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 RTC~~15~~ 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 DAM 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.

Real-Time replacement Energy settlements for Curtailed Import Transactions are described formulaically in Appendix K.

7.2.2.2   Financial Impact Charge for TUC 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~~Mitigation and Analysis Department 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~~LBMP from the RTD ~~price~~LBMP in the relevant interval, or zero. The RTC LBMP is the LBMP used to schedule the transaction. For hourly transactions, it is the 3rd, 4th, 5th and 6th LBMPs out of the RTC$_{15}$ evaluation. For intra-hourly transactions, it is the LBMP from the rolling RTC that scheduled the transaction.

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 DAM scheduled Energy injections minus the actual Energy injections at that Proxy Generator Bus for the dispatch hour.

Settlements for Financial Impact Charges for Import Transactions failing the NYISO checkout process are described formulaically in Appendix K.

7.3 TUC Settlements – Export Bilateral Transactions

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 megawatt hours; 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 megawatt hours, 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., the Proxy Generator Bus where Energy is scheduled to be withdrawn from the NYCA) for the Transaction, in $/MWh.

DAM TUC settlements for Export Bilateral Transactions are described formulaically in Appendix K.

7.3.1.1 Suppliers Scheduled Day-Ahead below Export Bilateral Contract Commitments

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 megawatt hours) necessary to supply the Transaction.

DAM settlements for Generators designated as the Suppliers of Energy for a Bilateral Transaction that are scheduled to produce less Energy than is necessary to supply the Transaction Export Bilateral Transactions are described formulaically in Appendix B.

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 megawatt hours; 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 megawatt hours; 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.

Balancing Market TUC settlements for Export Bilateral Transactions are described formulaically in Appendix K.

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

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 megawatt hours) necessary to supply the Transaction.

Real-Time Market settlements for Generators designated as the Suppliers of Energy for a Bilateral Transaction that are scheduled to produce less Energy than is necessary to supply the Transaction Export Bilateral Transactions are described formulaically in Appendix B.

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~~Mitigation and Analysis Department 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~~LBMP in the relevant interval from the RTC ~~price~~LBMP, or zero. The RTC LBMP is the LBMP used to schedule the transaction. For hourly transactions, it is the 3rd, 4th, 5th and 6th LBMPs out of the RTC$_{15}$ evaluation. For intra-hourly transactions, it is the LBMP from the rolling RTC that scheduled the transaction.

Settlements for Financial Impact Charges for Export Transactions failing the NYISO checkout process are described formulaically in Appendix K.

7.4 TUC Settlements – Wheel-Through Transactions

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 megawatt hours; 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 megawatt

hours, 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.

DAM TUC settlements for Wheel-through Bilateral Transactions are described formulaically in Appendix K.

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 megawatt hours; 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 megawatt hours; 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.

Balancing Market TUC settlements for Wheel-through Bilateral Transactions are described formulaically in Appendix K.

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~~ <u>Mitigation and Analysis Department</u> 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~~LBMP from the RTD ~~price~~LBMP in the relevant interval, or zero. The RTC LBMP is the LBMP used to schedule the transaction. For hourly transactions, it is the 3rd, 4th, 5th and 6th LBMPs out of the RTC$_{15}$ evaluation. For intra-hourly transactions, it is the LBMP from the rolling RTC that scheduled the transaction.

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.

Settlements for Financial Impact Charges for Wheel-Through Transactions failing the NYISO checkout process are described formulaically in Appendix K.

7.5 NYPA Transmission Adjustment Charge (NTAC)

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 (OATT) 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 megawatt hours.

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 megawatt hours.

7.6 Trading Hub Energy Settlements

7.6.1 Day-Ahead Market Energy Settlements at Trading Hub Point of Injection Buses

Each Trading Hub Energy Owner who bids a Bilateral Transaction into the Day-Ahead Market with a Trading Hub as its Point of Injection (Source) and has its schedule accepted by the NYISO will be charged the product of: (a) the Day-Ahead hourly zonal LBMP for the Load Zone associated with that Trading Hub; and (b) the Bilateral Transaction scheduled megawatts.

Day-Ahead Market Energy Settlements at Trading Hub Point of Injection Buses are described formulaically in Appendix K.

7.6.2 Real-Time Market Energy Settlements at Trading Hub Point of Injection Buses

Each Trading Hub Energy Owner who bids a Bilateral Transaction into the Real-Time Market with a Trading Hub as its Point of Injection (Source) and has its schedule accepted by the NYISO will be charged the product of: (a) the hourly integrated Real-Time LBMP for the Load Zone associated with that Trading Hub; and (b) the Bilateral Transaction scheduled megawatts.

Real-Time Market Energy Settlements at Trading Hub Point of Injection Buses are described formulaically in Appendix K.

7.6.3 Day-Ahead Market Energy Settlements at Trading Hub Point of Withdrawal Buses

Each Trading Hub Energy Owner who bids a Bilateral Transaction into the Day-Ahead Market with a Trading Hub as its Point of Withdrawal (Sink) and has its schedule accepted by the NYISO will be paid the product of: (a) the Day-Ahead hourly zonal LBMP for the Load Zone associated with that Trading Hub; and (b) the Bilateral Transaction scheduled megawatts.

Day-Ahead Market Energy Settlements at Trading Hub Point of Withdrawal Buses are described formulaically in Appendix K.

7.6.4 Real-Time Market Energy Settlements at Trading Hub Point of Withdrawal Buses

Each Trading Hub Energy Owner who bids a Bilateral Transaction into the Real-Time Market with a Trading Hub as its Point of Withdrawal (Sink) and has its schedule accepted by the NYISO will be paid the product of: (a) the hourly integrated Real-Time LBMP for the Load Zone associated with that Trading Hub; and (b) the Bilateral Transaction scheduled megawatts.

Real-Time Market Energy Settlements at Trading Hub Point of Withdrawal Buses are described formulaically in Appendix K.

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8.   ANCILLARY SERVICES CHARGES

8.1   NYISO Annual Budget Charge and Other Non-Budget Rate Schedule 1 Charges and Payments (OATT)

For purposes of Section 8.1 of this manual and the related provisions in Appendix M of this manual, the term *Transmission Customer* refers to both a Transmission Customer taking service under the *NYISO OATT* and a Customer taking service under the *NYISO Services Tariff*.

The NYISO will bill each Transmission Customer on a monthly basis under Rate Schedule 1 to recover the NYISO's annual budgeted costs as set forth in Section 8.1.1of this manual.

The NYISO will separately bill each Transmission Customer under Rate Schedule 1 for certain other charges and payments not related to the NYISO annual budget charge. Specifically, the NYISO will bill each Transmission Customer on a quarterly basis to recover NERC and NPCC charges as set forth in Section 8.1.2 of this manual. The NYISO will also bill each Transmission Customer on a monthly basis to recover the following costs or allocate the following received payments under Rate Schedule 1:

a. Bad debt loss charges as set forth in Section 8.1.3;
b. Working Capital Fund charges as set forth in Section 8.1.4;
c. Non-NYISO facilities payment charges as set forth in Section 8.1.5;
d. Charges to recover costs for payments made to Suppliers pursuant to incremental cost recovery for units that responded to Local Reliability Rules I-R3 and I-R5 as set forth in Section 8.1.6;
e. Charges to recover and payments to allocate residual costs as set forth in Section 8.1.7;
f. Charges for Special Case Resources and Curtailment Service Providers called to meet reliability needs as set forth in Section 8.1.8;
g. Charges to recover DAMAP costs as set forth in Section 8.1.9;
h. Charges to recover Import Curtailment Guarantee Payment costs as set forth in Section 8.1.10;
i. Charges to recover Bid Production Cost guarantee payment costs as set forth in Section 8.1.11;
j. Charges to recover and payments to allocate settlements of disputes as set forth in Section 8.1.12; and
k. Payments to allocate financial penalties collected by the ISO as set forth in Section 8.1.13.

The calculation methodologies for the NYISO annual budget charge and other non-budget Rate Schedule 1 charges and payments are illustrated formulaically in Appendix M of this manual.

8.1.1　　　NYISO Annual Budget Charge

The NYISO will charge, and each Transmission Customer will pay, a charge for the NYISO's recovery of its annual budgeted costs. The NYISO annual budgeted costs that are recoverable through Rate Schedule 1 are set forth in Section 8.1.1.1 of this manual. The NYISO will calculate the charge for the recovery of these NYISO annual budgeted costs from each Transmission Customer on the basis of its participation in physical market activity as illustrated formulaically in Appendix M of this manual. The NYISO will calculate this charge for each Transmission Customer on the basis of its participation in non-physical market activity(which includes engaging in Virtual Transactions or purchasing Transmission Congestion Contracts) , the Special Case Resource program, and the Emergency Demand Response program as illustrated formulaically in Appendix M of this manual. The NYISO will credit the revenue collected from Transmission Customers based on their participation in non-physical market activity, the Special Case Resource program, and the Emergency Demand Response program to each Transmission Customer on the basis of its physical market activity as illustrated formulaically in Appendix M of this manual.

8.1.1.1　　　NYISO Annual Budgeted Costs

The NYISO annual budgeted costs to be recovered through Rate Schedule 1 include, but are not limited to, the following costs associated with the operation of the NYS Transmission System by the NYISO, and the administration of the ISO Tariffs and ISO Related Agreements by the NYISO:

- Processing and implementing requests for Transmission Service including support of the NYISO OASIS node;
- Coordination of Transmission System operation and implementation of necessary control actions by the NYISO and support for these functions;
- Performing centralized security constrained dispatch to optimally re-dispatch the NYS Power System to mitigate transmission Interface overloads and provide balancing services;
- Costs related to the NYISO's administration and operation of the LBMP market and all other markets administered by the NYISO;
- Costs related to the NYISO's administration of Control Area Services;
- Costs related to the NYISO's administration of the NYISO's Market Power Mitigation Measures and the NYISO's Market Monitoring Plan;
- Costs related to the maintenance of reliability in the NYCA;
- Costs related to the provision of Transmission Service;
- Preparation of settlement statements;
- New York State Transmission System studies, when the costs of the studies are not recoverable from a Transmission Customer;
- Engineering services and operations planning;
- Data and voice communications network service coordination;
- Metering maintenance and calibration scheduling;
- Record keeping and auditing;

- Training of NYISO personnel;
- Development and maintenance of information, communication, and control systems;
- Professional services;
- Carrying costs on NYISO assets, capital requirements, and debts;
- Tax expenses, if any:
- Administrative and general expenses;
- Insurance premiums and deductibles related to NYISO operations;
- Any indemnification of or by the NYISO pursuant to Section 2.11.2 of the *NYISO OATT* or Section 12.4 of the *NYISO Services Tariff*;
- Regulatory fees; and
- The NYISO's share of the expenses of Northeast Power Coordinating Council (NPCC), Inc. or its successor.

8.1.2 NERC and NPCC Charges

The NYISO receives an invoice from NERC and NPCC (as defined below) on a quarterly basis for the recovery of the upcoming calendar quarter's costs related to the dues, fees, and related charges of:

1. The NERC for its service as the Electric Reliability Organization for the United States (*ERO*), recovered pursuant to FERC Docket Nos. RM05-30-000, RR06-1-000, and RR06 3-000 and related dockets, and

2. The NPCC : Cross-Border Regional Entity, Inc , or its successors, incurred to carry out functions that are delegated by the NERC and are related to ERO matters pursuant to Section 215 of the FPA.

The NYISO will charge on a quarterly basis, and each Transmission Customer taking service under the ISO Tariffs will pay, a charge for the recovery of the NERC and NPCC costs as illustrated formulaically in Appendix M of this manual.

8.1.3 Bad Debt Loss Charge

The NYISO will charge, and each Transmission Customer will pay, a charge for the collection of costs related to bad debt losses in accordance with the methodology established in Attachment U of the *NYISO OATT*.

8.1.4 Working Capital Fund Charge

The NYISO will charge, and each Transmission Customer will pay, a charge for the collection and maintenance of the Working Capital Fund in accordance with the methodology established in Attachment V of the *NYISO OATT*.

8.1.5 Non-NYISO Facilities Payment Charge

The NYISO will charge, and each Transmission Customer will pay, a charge, as illustrated formulaically in Appendix M of this manual for the recovery of the costs for the NYISO's

monthly payments to the owners of facilities that are needed for the economic and reliable operation of the NYS Transmission System. At present, the NYISO makes such payments to:

1. Consolidated Edison Co. of New York, Inc. (ConEd) for the purchase, installation, operation, and maintenance of phase angle regulators at the Branchburg-Ramapo Interconnection between the NYISO and PJM Interconnection, LLC, and

8.1.6 Rochester Gas & Electric Corporation for the installation of a 135 MVAR Capacitor Bank at Rochester Station 80 on the cross-state 345 kV system.Payments Made to Generators Pursuant to Incremental Cost Recovery for Units Responding to Local Reliability Rules I-R3 and I-R5

The NYISO will charge, and each Transmission Customer will pay based on its Withdrawal Billing Units, a charge for the recovery of the costs of payments to Suppliers pursuant to the incremental cost recovery for units that responded to either (i) Local Reliability Rule I-R3 or (ii) Local Reliability Rule I-R5, as applicable, for each month, as illustrated formulaically in Appendix M of this manual.

8.1.7 Residuals Costs Payment\Charge

The NYISO's payments for market transactions by Transmission Customers will not equal the NYISO's payments to Suppliers for market transactions. Part of the difference consists of Day-Ahead Congestion Rent, which is balanced by the TOs and discussed in Section 10.1 of this manual. Part of the difference also involves Storm Watch costs, which are described in Section 8.1.7.1 of this manual. The remainder comprises a residual adjustment, which the NYISO will calculate and each Transmission Customer will receive or pay on the basis of its Withdrawal Billing Units. The most significant component of the residual adjustment is the residual costs payment or charge as illustrated formulaically in Appendix M of this manual.

8.1.7.1 Storm Watch Costs

This section describes how Storm Watch costs involve redistributing balancing congestion residuals from NYCA Transmission Customers to Transmission Customers in Load Zone J (N.Y.C.).

Storm Watch, which is also known as Thunderstorm Alert or TSA, is a Local Reliability Rule (LRR) that is activated during actual or anticipated severe weather conditions under which region-specific portions of the New York Transmission System are operated in a more conservative manner by reducing transmission transfer limits. As provided for in *NYISO Services Tariff* Section 4.1.8, the NYISO calculates Storm Watch Costs by multiplying the real-time Shadow Price of any binding constraint associated with a Storm Watch, by the higher of (i) zero; or (ii) the scheduled Day-Ahead flow across the constraint minus the actual real-time flow across the constraint.

Consolidated Edison is the only TO that has the authority to activate the Storm Watch LRR. As a result, and as further provided for in *NYISO Services Tariff* Section 4.1.8,

redispatching costs incurred as a result of reductions in Transfer Capability caused by activation of a Storm Watch are aggregated and recovered on a monthly basis by the NYISO exclusively from Transmission Customers in Load Zone J (N.Y.C.).

Upon receipt of a request from ConEd to implement a Storm Watch, the NYISO applies the requisite transmission constraint sets to redispatch the transmission grid in a fashion that reliability is effectively supported for the N.Y.C. region. Since the NYISO must manage the overall reliability of the NYCA during the implementation and termination of a the Storm Watch protocols, it may be necessary to ramp into and out of the Storm Watch contingencies in a manner that NYCA transmission grid reliability is also maintained. As a result, the implementation of Storm Watch protocols may lag ConEd's request for implementation, and the termination may lag ConEd's direction to terminate a Storm Watch in order to effectively manage NYCA reliability.

As provided for in *NYISO Services Tariff* Section 4.1.8, the NYISO calculates Storm Watch redispatch costs by multiplying the real-time Shadow Price of any binding constraint associated with a Storm Watch, by the higher of (i) zero or (ii) the scheduled Day-Ahead flow across the constraint minus the actual real-time flow across the constraint, adjusted for instances when DAM flows would have created real-time congestion even in the absence of a Storm Watch event. Storm Watch redispatch costs and associated allocations are computed outside of the NYISO settlement software application; therefore, the cost reallocation process is implemented through adjustments applied to affected customers' monthly invoices.

The calculation of Storm Watch redispatch costs and associated allocations are described formulaically in Appendix M of this manual.

8.1.8 Recovery of Special Case Resources and Curtailment Service Providers Costs

The NYISO will charge, and each Transmission Customer will pay, a charge for the recovery of Special Case Resources (SCR) and Curtailment Service Providers (CSP) costs for each month.

This charge will be equal to the sum of the hourly charges for the Transmission Customer, as illustrated formulaically in Appendix M of this manual, for each hour in the relevant month and, where applicable, for each Subzone.

8.1.8.1 Recovery of Costs of Payments for Special Case Resources and Curtailment Service Providers Called to Meet the Reliability Needs of a Local System

The NYISO will recover the costs of payments to SCRs and CSPs that were called to meet the reliability needs of a local system. To do so, the NYISO will charge, and each Transmission Customer that serves Load in the Subzone for which the reliability services of the SCRs and CSPs were called will pay, based on its Withdrawal Billing Units, a charge as illustrated formulaically in Appendix M of this manual, for each Subzone.

8.1.8.2 Recovery of Costs of Payments for Special Case Resources and Curtailment Service Providers Called to Meet the Reliability Needs of the New York Control Area

The NYISO will recover the costs of payments to SCRs and CSPs called to meet the reliability needs of the NYCA. To do so, the NYISO will charge, and each Transmission Customer will pay, based on its Withdrawal Billing Units, a charge as illustrated formulaically in Appendix M of this manual .

8.1.9 Day-Ahead Margin Assurance Payments

The NYISO will charge, and each Transmission Customer will pay, a charge for the recovery of Day-Ahead Margin Assurance Payments (DAMAP) costs for each month. This monthly charge shall be equal to the sum of the charges and credits for the Transmission Customer, as broken out in the following two subsections and illustrated formulaically in Appendix M of this manual, for each hour or each day, as applicable, in the relevant month and for each Subzone, where applicable.

8.1.9.1 Day-Ahead Margin Assurance Payments Resulting from Meeting the Reliability Needs of a Local System

The NYISO will recover the costs for DAMAPs incurred to compensate Resources for meeting the reliability needs of a local system, as illustrated formulaically in Appendix M of this manual.

8.1.9.2 Day-Ahead Margin Assurance Payments Resulting from Meeting the Reliability Needs of the NYCA

The NYISO will recover the costs for DAMAPs incurred to compensate Resources for meeting the reliability needs of the NYCA, as illustrated formulaically in Appendix M of this manual.

8.1.10 Import Curtailment Guarantee Payments

The NYISO will charge, and each Transmission Customer will pay, a charge for the recovery of the costs of Import Curtailment Guarantee Payments paid to Import Suppliers each month. This monthly charge will be equal to the sum of the charges and credits for the Transmission Customer, as illustrated formulaically in Appendix M of this manual, for each hour in the relevant month .

8.1.11 Bid Production Cost Guarantee Payments

The NYISO will charge, and each Transmission Customer will pay, a charge for the recovery of Bid Production Cost Guarantee (BPCG) and Demand Reduction Incentive Payment costs for each month. This monthly charge will be equal to the sum of the charges and credits for the Transmission Customer, as broken out below and described formulaically in Appendix M of this manual, for each day and for each Subzone, where applicable.

8.1.11.1 Recovery of Costs of Demand Reduction Bid Production Cost Guarantees and Demand Reduction Incentive Payments

After accounting for imbalance charges paid by Demand Reduction Providers, the NYISO will recover the costs associated with Demand Reduction BPCG payments and Demand Reduction Incentive Payments from Transmission Customers pursuant to the methodology established in Attachment R of the *NYISO OATT*.

8.1.11.2 Recovery of the Costs of Bid Production Cost Guarantees for Additional Generating Units Committed to Meet Forecast Load

If the sum of all Bilateral Transaction schedules, excluding schedules of Bilateral Transactions with Trading Hubs as their POWs, and all Day-Ahead Market purchases to serve Load in the Day-Ahead schedule is less than the NYISO's Day-Ahead forecast of Load, the NYISO may commit Resources in addition to the reserves that it normally maintains to enable it to respond to contingencies to meet the NYISO's Day-Ahead forecast of Load. The NYISO will recover a portion of the costs associated with BPCG payments for the additional Resources committed Day-Ahead to meet the Day-Ahead forecast of Load from Transmission Customers pursuant to the methodology established in Attachment T of the *NYISO OATT*. The NYISO will recover the residual costs of such BPCG payments not recovered through the methodology in Attachment T of the *NYISO OATT* through the methodology outlined in Section 8.1.11.6 of this manual.

8.1.11.3 Recovery of Costs for Bid Production Cost Guarantees Resulting from Meeting the Reliability Needs of a Local System

The NYISO will recover the costs for BPCG payments incurred to compensate Suppliers for their Resources, other than SCRs, that are committed or dispatched to meet the reliability needs of a local system through a charge for each subzone, as illustrated formulaically in Appendix M of this manual.

8.1.11.4 Recovery of Costs of Bid Production Cost Guarantees for Special Case Resources Called to Meet the Reliability Needs of a Local System

The NYISO will recover the costs of BPCG payments incurred to compensate SCRs called to meet the reliability needs of a local system. To do so, the NYISO will charge, and each Transmission Customer that serves Load in the Subzone where the SCR is located will pay, a charge, as illustrated formulaically in Appendix M of this manual.

8.1.11.5 Recovery of Costs of Bid Production Cost Guarantees for Special Case Resources Called to Meet the Reliability Needs of the New York Control Area

The NYISO will recover the costs of BPCG payments incurred to compensate SCRs called to meet the reliability needs of the NYCA. To do so, the NYISO will charge, and each

Transmission Customer that serves Load in the NYCA will pay, a charge, as illustrated formulaically in Appendix M of this manual.

8.1.11.6 Recovery of Costs of New York Control Area Reliability Bid Production Cost Guarantees

The NYISO will recover the costs of all BPCG payments not recovered through Sections 8.1.11.1, 8.1.11.2, 8.1.11.3, 8.1.11.4, and 8.1.11.5 of this manual, including the residual costs of BPCG payments for additional Resources not recovered through the methodology in Attachment T of the *NYISO OATT*, from all Transmission Customers, as illustrated formulaically in Appendix M of this manual.

8.1.12 Dispute Resolution Payment\Charge

The NYISO will calculate, and each Transmission Customer will receive or pay, a dispute resolution payment or charge, as illustrated formulaically in Appendix M of this manual, for the distribution of funds received by the NYISO or the recovery of funds incurred by the NYISO in the settlement of a dispute.

8.1.13 Credit for Financial Penalties

The NYISO will distribute to each Transmission Customer on a monthly basis, as illustrated formulaically in Appendix M of this manual, any payments that it has collected from Transmission Customers to satisfy: (i) Financial Impact Charges issued pursuant to Sections 4.5.3.2 and 4.5.4.2 of the *NYISO Services Tariff*; (ii) ICAP sanctions issued pursuant to Section 5.12.12 of the *NYISO Services Tariff*; (iii) ICAP deficiency charges pursuant to Section 5.14.3.1 of the *NYISO Services Tariff*, except as provided in Section 5.14.3.2 of the *NYISO Services Tariff*; (iv) market power mitigation financial penalties pursuant to Section 23.4.3.6 of Attachment H of the *NYISO Services Tariff*, except as provided in Section 23.4.4.3.2 of Attachment H of the *NYISO Services Tariff*; and (v) any other financial penalties set forth in the *NYISO Services Tariff* or the *NYISO OATT*. The NYISO will perform this calculation separately for the allocation of the revenue from each financial penalty.

8.2 Scheduling, System Control, and Dispatch Service (Services Tariff)

8.2.1 Annual Budget ~~and FERC Regulatory Fees~~and Other Non-Budget Charges and Payments

The terms of Schedule 1 of the NYISO OATT are hereby incorporated by reference into this Services Tariff. In applying the terms of Schedule 1 of the NYISO OATT in connection with this Tariff, all terms in Schedule 1 of the NYISO OATT that are applicable to "Transmission Customers" shall be similarly applicable to "Customers" under this Rate Schedule 1, and the NYISO shall interpret all other defined terms and cross references in

Schedule 1 that are specific to the NYISO OATT consistent with the similar terms and provisions of this Tariff, unless otherwise specified.Placeholder

8.2.2 NYISO Unbudgeted Cost Component

Placeholder

8.3 Voltage Support Service

Transmission Customers pay the NYISO for Voltage Support Service. The NYISO computes the Voltage Support Service rate as the quotient of: (a) (i) the sum of the projected NYISO payments to generation facilities and Qualified Non-Generator Voltage Support Resources providing Voltage Support Service, based on Sections 15.2.2.1, 15.2.2.2, and 15.2.2.3 of Rate Schedule 2 of the ISO Services Tariff, plus (ii) the total of prior year payments to generation facilities and Qualified Non-Generator Voltage Support Resources supplying Voltage Support Service less the total of payments received by the NYISO from Transmission Customers and LSEs in the prior year for Voltage Support Service (including all payments for penalties); and (b) the annual forecasted transmission usage for the year as projected by the NYISO, including Load within the NYCA, Exports and Wheels Through.

Transmission Customers engaging in Wheels Through, Exports and Purchases from the LBMP Market where the Energy is delivered to a NYCA interconnection with another Control Area pay the NYISO a charge for Voltage Support Service equal to the Voltage Support Service rate, as determined above, multiplied by their Energy scheduled in the hour. LSEs pay to the NYISO a charge for Voltage Support Service equal to the Voltage Support Service rate, as determined above, multiplied by the Energy consumed by the LSE's Load located in the NYCA in the hour, provided however, LSEs taking service under Section 5 of the OATT to supply Station Power as a third-party provider pay to the NYISO a charge for Voltage Support Service equal to the Voltage Support Service rate, as determined above, multiplied by the LSE's Station Power provided under Section 5 of the OATT. The NYISO credits Revenue collected by application of this charge, on a Load ratio share basis, to Transmission Customers engaging in Wheels Through, Exports and Purchases from the LBMP Market where the Energy is delivered to a NYCA interconnection with another Control Area in that day and LSEs serving New York Control Area Load in that day.

For LSEs and all Wheels Through, Exports and Purchases from the LBMP Market for Energy delivered to a NYCA interconnection with another Control Area, the NYISO calculates the payment hourly. The NYISO bills each Transmission Customer or LSE monthly.

The allocation of the NYISO's costs associated with the provision of Voltage Support Service is illustrated formulaically in Appendix M.

8.4 Regulation and Frequency Response Service

The NYISO charges Transmission Customers and LSEs serving Load in the NYCA for Regulation and Frequency Response for each hour. For all Actual Energy Withdrawals by

Load located in the NYCA, the LSE is considered the Transmission Customer on all Transmission Service and purchases in the LBMP Markets. The NYISO charges Transmission Customers or LSEs taking service under Section 5 of the ISO OATT to supply Station Power as third-party providers for Regulation and Frequency Response for each day. The Regulation and Frequency Response charge is determined as an hourly or a daily rate, as appropriate, multiplied by the LSE's or Transmission Customer's Load for the hour or by the Transmission Customers or LSEs withdrawals to provide Station Power as a third party provider for the day.

The Regulation and Frequency Response Rate, for the hour or for the day, as appropriate, is computed as the quotient of: (a) the aggregate of Day-Ahead Market and Real-time payments made by the NYISO to Regulation Service Suppliers, including Regulation Revenue Adjustment payments, for the hour or the day, as appropriate, less charges paid by Suppliers, for the hour or the day, as appropriate, for (i) poor Regulation Service performance, (ii) real-time imbalances, and (iii) Regulation Revenue Adjustment charges, less charges paid by Generators that do not provide Regulation Service and and do not follow their RTD Base Points sufficiently accurately, as described in Rate Schedule 3-A (Section 15.3A) of the NYISO Services Tariff for the hour or for the day, and (b) the total Load in the NYCA for the hour or for the day, as appropriate.

In any hour where the charges paid by Generators and Suppliers exceed the payments made to Suppliers for this service, the NYISO will not assess a charge against any LSE and any surplus will be applied to the following hour as an offset to subsequent payments. Charges to be paid by Transmission Customers for this service are aggregated to render a monthly charge. The NYISO credits charges paid for Regulation and Frequency Response by Transmission Customers or LSEs taking service under Section 5 of the NYISO OATT to supply Station Power as third-party providers for the day on a Load ratio share basis to Transmission Customers and LSEs serving Load in the NYCA for that day.

The allocation of the NYISO's costs associated with the provision of Regulation and Frequency Response Service is illustrated formulaically in Appendix M

8.5 Energy Imbalance Service

For each Transmission Customer that has executed a Service Agreement under the NYISO Services Tariff, Energy Imbalance Service is considered to be supplied by the Real-Time Market and is charged at the Real-Time LBMP. For each Transmission Customer that is not a Customer under the Services Tariff and is receiving service under Section 3 or Section 4 of the OATT, the NYISO shall establish a deviation band of +/- 1.5 percent (with a minimum of 2 MW) of the scheduled transaction to be applied hourly to any Energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s). Parties should attempt to eliminate Energy imbalances within the limits of the deviation band within thirty (30) days or within such other reasonable period of time as may be established by the NYISO that is generally accepted in the region and consistently adhered to by the NYISO. If an Energy imbalance is not corrected within thirty (30) days or such other reasonable period of time as may be established by the NYISO that is generally accepted in the region and consistently adhered to by the NYISO, the Transmission Customer will compensate the NYISO for such service, subject to the charges described

below. Also, Energy imbalances outside the deviation band will be subject to these charges, as well.

For hours when the Transmission Customer's Actual Energy Withdrawals are greater than that customer's scheduled Energy delivery and applicable tolerance band, the Transmission Customer is charged an amount equal to the greater of 150% of the Real-Time LBMP at the Point of Delivery (Withdrawal) or $100 per megawatt hour. In the event that the Transmission Customer's Actual Energy delivery exceeds that customer's Actual Energy Withdrawals, the Transmission Customer will not receive payment for such Energy.

Energy imbalances resulting from inadvertent interchange between Control Areas will continue to be addressed by the procedures that Control Area operators currently use to address such imbalances. Any increase or decrease in costs resulting from pay back of accumulated inadvertent interchange will be included as a component of the Residual Adjustment.

8.6   Operating Reserves Service

Each Transmission Customer engaging in an Export and each LSE pays an hourly charge equal to the product of: (a) the cost to the NYISO of providing all Operating Reserves for a given hour; and (b) the ratio of (i) the LSE's hourly Load or the Transmission Customer's hourly scheduled Export to (ii) the sum of all Load in the NYCA and all scheduled Exports for a given hour. The cost to the NYISO of providing Operating Reserves in each hour is equal to the total amount that the NYISO pays to procure Operating Reserves on behalf of the market in the Day-Ahead Market and the Real-Time Market, less payments collected from entities that are scheduled to provide less Operating Reserves in the Real-Time Market than in the Day-Ahead Market during that hour. The NYISO aggregates the hourly charges to produce a total charge for a given Dispatch Day.

Transmission Customers taking service under Section 5 of the OATT to supply Station Power as third-party providers pay the NYISO a daily charge for Operating Reserves Service equal to the product of (a) the cost to the NYISO of providing all Operating Reserves for the day less any revenues from penalties collected during the day and (b) the ratio of (i) the Transmission Customer's Station Power supplied under Section 5 of the OATT for the day to (ii) the sum of all Load in the NYCA and all scheduled Exports for the day. The NYISO credits the daily charges paid for Operating Reserves by Transmission Customers taking service under Section 5 of the OATT to supply Station Power as third-party providers on a Load ratio share basis to the Load in the NYCA for that day and all scheduled Exports for that day.

Transmission Customers, including LSEs, may provide for Self-Supply of Operating Reserve by placing generation facilities supplying any one of the Operating Reserves under NYISO Operational Control. The amount that any such customer will be charged for Operating Reserves Services will be reduced by the market value of the services provided by the specified generation facilities as determined in the NYISO Services Tariff.

The allocation of the NYISO's costs associated with the provision of Operating Reserves Service is illustrated formulaically in Appendix M.

8.6.1   Quick-Start Reserves Service

Amounts due to a Supplier of Quick Start Reserves, pursuant to this Rate Schedule 6 (Section 15.6) of the Services Tariff, that are attributable to local reliability are recovered from LSEs in the Transmission District of the Supplier selling the Quick Start Reserves on the basis of each LSE's contribution to Load share in the month the payment obligation is incurred.

8.7   Black Start Service

Transmission Customers pay a Black Start and System Restoration Services charge on all Transactions to supply Load in the NYCA (including Internal Wheels and Import Transactions) equal to the product of (a) the Transmission Customer's hourly Load Ratio Share and (b) the hourly embedded cost charge for Black Start and System Restoration Services (net of all payments forfeited due to a Generator's failure to pass a required test of its ability to provide Black Start and System Restoration Services).

The full restoration of the NYS Power System will require additional Black Start and System Restoration Services from Generators, which are located in local Transmission Owner areas and which are not presently listed in the NYISO Black Start Plan. Although the NYISO Plan will restore a major portion of the NYS Power System, there are portions of the NYS Power System that will remain under Transmission Owner restoration control. Where the Transmission Owners' restoration plans require additional local Black Start and System Restoration Services, the NYISO makes payments for such local services directly to the Generators that provide them, pursuant to Section 15.5.2 of Rate Schedule 5 of the NYISO Services Tariff, except with respect to Black Start and System Restoration Services payments that are subject to Section 3.1 of that Rate Schedule. The LSEs in those local Transmission Owner areas will be additionally charged for Black Start and System Restoration Services by the NYISO using the formula set forth in the following paragraph, except with respect to Black Start and System Restoration Services changes that are subject to Section 15.5.3.2 of Rate Schedule 5 to the NYISO Services Tariff.

The NYISO charges LSEs in those local Transmission Owner areas an amount equal to the product of (a) the Transmission Customer's hourly Load Ratio Share of Load requiring local Black Start and System Restoration Services, and (b) the hourly embedded cost charge for providing local Black Start and System Restoration Services capability (net of all payments forfeited due to a local generation facility's failure to pass a Black Start and System Restoration Services capability test), as described in Rate Schedule 5 (Section 15.5) of the Services Tariff.

The allocations of the NYISO's costs associated with the provision of Black Start and Local Black Start and System Restoration Service are illustrated formulaically in Appendix M.

8.8   Penalty Cost Recovery

This section describes the NYISO's cost recovery process, as provided for under Rate Schedule 11 (Section 6.11) of the NYISO OATT, for monetary penalties assessed by the

FERC, NERC and/or NPCC against the NYISO as the Registered Entity for a violation of a NERC Reliability Standard(s).

8.8.1 Allocation of Costs Associated with NERC Penalty Assessments When NYISO is the Registered Entity

The defined terms referenced herein are defined in Section 6.11.1.2 of Schedule 11 or Section 1 of the OATT. If the FERC, NERC and/or NPCC assesses a monetary penalty against the NYISO as the Registered Entity for a violation of a NERC Reliability Standard(s), and the conduct of a Customer or Customers contributed to the Reliability Standard violation(s) at issue, then the NYISO may directly allocate such penalty costs or a portion thereof to the Customer or Customers whose conduct contributed to the Reliability Standards violation(s), provided that all of the following conditions have been satisfied:

- Pursuant to the Compliance Monitoring and Enforcement Program (CMEP), the Customer or Customers received notice and an opportunity to fully participate in the underlying CMEP proceeding;
- The CMEP proceeding produced a root cause finding, subsequently filed with FERC, that the Customer contributed, either in whole or in part, to the NERC Reliability Standards violation(s); and
- A NERC filing of the root cause finding identifying the Customer's or Customers' conduct as causing or contributing to the Reliability Standards violation charged against the NYISO as the Registered Entity is made at FERC.

The NYISO will notify the Customer or Customers found to have contributed to a violation, either in whole or in part, in the CMEP proceedings. Such notification shall set forth in writing the ISO's intent to invoke this section and directly assign the costs associated with a monetary penalty to the Customer or Customers. Such notification shall (i) state that the NYISO believes the criteria for direct assignment and allocation of costs under this Schedule have been satisfied; and (ii) describe the underlying factual basis supporting a penalty cost assignment, including a description of the conduct contributing to the violation and the nature of the violation of the ISO Tariffs or ISO Related Agreement requirements. A failure by a Customer or Customers to participate in the CMEP proceedings will not prevent the NYISO from directly assigning the costs associated with a monetary penalty to the responsible Customer or Customers provided all other conditions set forth herein have been satisfied.

Where the Regional Entity's and/or NERC's root cause analysis finds that more than one party's conduct contributed to the Reliability Standards violation(s), the NYISO shall inform all involved Customers and shall make an initial apportionment for purposes of the cost allocation on a basis reasonably proportional to the parties' relative fault consistent with NERC's root cause analysis. If the NYISO and the involved Customer(s) agree on the proportion of penalty cost allocation, such agreement shall be submitted to the FERC pursuant to Section 205 of the Federal Power Act for approval. Should the Customer(s) disagree with the NYISO's initial apportionment of the penalty based on each party's relative fault, then the parties shall meet in an attempt to informally resolve the penalty allocation. If the parties cannot agree informally, the matter shall be submitted to the FERC pursuant to Section 205 of the Federal Power Act.

Once there is a final order by FERC regarding the NYISO's ability to directly assign the penalty amounts, the NYISO will include such amounts in the appropriate Customer's or Customers' next monthly invoice. Such payment amount will be due with interest calculated at the FERC authorized refund rate from the date of payment of the penalty by the NYISO, provided however, nothing precludes the Customer or Customers from paying such penalty when it becomes due for the NYISO to avoid paying interest costs. If the Customer pays such penalty under protest when it becomes due and prior to a final order by FERC and such Customer is thereafter found not liable, the Customer is entitled to a refund of the penalty amount from the NYISO, with interest calculated at the FERC authorized refund rate from the date the Customer pays the penalty.

The allocation of costs associated with NERC penalty assessments is illustrated formulaically in Appendix M.

8.8.2 Allocation of Costs Associated with NERC Penalty Assessments When Customer is the Registered Entity

If the FERC, NERC and/or NPCC assesses a monetary penalty against a Customer as the Registered Entity for a violation of a NERC Reliability Standard(s), and the conduct of the NYISO contributed to the Reliability Standard violation(s) at issue, then such Customer may directly allocate such penalty costs or portion thereof to the NYISO to the extent the NYISO's conduct contributed to the Reliability Standards violation(s), provided that the following conditions have been satisfied:

- Pursuant to the CMEP, the NYISO received notice and an opportunity to fully participate in the underlying CMEP proceeding;
- The CMEP proceeding produced a root cause finding, subsequently filed with FERC, that the NYISO contributed, either in whole or in part, to the NERC Reliability Standards violation(s); and
- A NERC filing of the root cause finding identifying the NYISO's conduct as causing or contributing to the Reliability Standards violation charged against the Customer as the Registered Entity is made at FERC.

The Customer must notify the NYISO if the NYISO is found to have contributed to a violation, either in whole or in part in the CMEP proceedings. Such notification must set forth in writing the Customer's intent to invoke Section 6.11.1.4 of Schedule 11 of the OATT and directly assign the costs associated with a monetary penalty to the NYISO. Such notification must (i) state that the Customer believes the criteria for direct assignment and allocation of costs under this provision have been satisfied; and (ii) describe the underlying factual basis supporting a penalty cost assignment, including a description of the conduct contributing to the violation and, where applicable, the nature of the violation of the NYISO Tariffs or NYISO Related Agreement requirements. A failure by the ISO to participate in the CMEP proceedings will not prevent the Customer from directly assigning the costs associated with a monetary penalty to the NYISO provided all other conditions set forth herein have been satisfied.

Where the Regional Entity's and/or NERC's root cause analysis finds that the NYISO's conduct contributed to the Reliability Standards violation(s), the Customer must inform the NYISO and make an initial apportionment for purposes of the cost allocation on a basis

reasonably proportional to the parties' relative fault consistent with NERC's root cause analysis. If the NYISO and the involved Customer agree on a proportion of penalty cost allocation, such agreement must be submitted to the FERC pursuant to Section 205 of the Federal Power Act. Should the NYISO disagree with the Customer's initial apportionment of the penalty based on each party's relative fault, then the parties will meet in an attempt to informally resolve the penalty allocation. If the parties cannot agree informally, the matter will be submitted to the FERC pursuant to Section 205 of the Federal Power Act.

Once there is a final order by FERC regarding the Customer's direct assignment of costs to the NYISO, the NYISO will pay such amount with interest calculated at the FERC authorized refund rate from the date of payment of the penalty by the Registered Entity. The NYISO will thereafter pursue the recovery of such costs in accordance with Section 8.8.4, below. Nothing precludes the NYISO from paying such penalty when it becomes due for the Registered Entity to avoid paying interest costs. If the NYISO pays such penalty under protest when it becomes due and prior to a final order by FERC and the NYISO thereafter is found not liable, the NYISO is entitled to a refund of the penalty amount from the Customer with interest calculated at the FERC authorized refund rate from the date of payment of the penalty by the NYISO. The NYISO will thereafter refund any amounts that were collected from all Customers pursuant to Section 8.8.4, below.

The allocation of costs associated with NERC penalty assessments is illustrated formulaically in Appendix M.

8.8.3　　Allocation of Costs Associated with Other Reliability Penalty Assessments

The NYISO is responsible for performing specific functions under other applicable state and federal regulatory requirements and may be assessed penalties by other regulatory bodies for violations of applicable regulatory requirements. Section 8.8.4 of this manual furnishes a mechanism by which the NYISO may seek to recover monetary penalties imposed by such regulatory authorities. Penalties that are assessed against the NYISO on or after the effective date of this Section shall be recoverable as provided in this Section regardless of the date of the violation(s) for which the penalty is assessed. Notwithstanding any provisions of the NYISO Tariffs or NYISO Related Agreements, including those provisions requiring stakeholder approval for Section 205 filings in certain instances, the ISO has the independent authority to make Section 205 filings in accordance with the provisions of this Schedule 11 after consultation with the Management Committee as provided in Section 5.1.1.3 of the Services Tariff of Section 2.11.6(c) of the NYISO OATT.

8.8.4　　Allocation of Costs Associated with Penalty Assessments

Where a particular Customer or Customers cannot be identified as the root cause of a penalty assessment against the NYISO or if the NYISO is assessed a penalty because of its own action or inaction that resulted in a reliability standard violation or a violation of applicable state or federal regulatory requirements, or if the NYISO is allocated a penalty as described above in Section 8.8.2, the NYISO may seek to recover such penalty costs in

accordance with this provisions described herein. Any penalty assessments must first be approved by FERC on a case-by-case basis, as provided in Reliability Standard Compliance and Enforcement in Regions with Regional Transmission Organizations or Independent System Operators, Docket No. AD07-12-000, 122 FERC ¶ 61,247 (2008), or any successor policy.

Any and all costs associated with the imposition of NERC Reliability Standards penalties or penalties assessed by other regulatory authorities that may be assessed against the NYISO either directly by NERC, other regulatory authority or allocated by a Customer or Customers under Schedule 11 (Section 6.11) of the OATT will be (i) paid by the NYISO notwithstanding the limitation of liability provisions in the OATT Tariff or the Services Tariff; and (ii) recovered through an allocation of 50% to all injection billing units and 50% to all withdrawal billing units, after consultation with the Management Committee as provided in Section 5.1.1.3 of the Services Tariff or Section 2.11.6(c) of the NYISO OATT, or as otherwise approved by the FERC. The rate to be applied to injection and withdrawal billing units in each month is the quotient of the amount of these costs to be included in the month divided by the sum of the total injection and withdrawal billing units for the month. This rate is then multiplied by each Transmission Customer's aggregate injection and withdrawal billing units for the month. The Transmission Customer's injection billing units are based on Actual Energy Injections (for all internal injections) or Scheduled Energy Injections (for all Import Energy injections) in the New York Control Area, including injections for wheels through. The Transmission Customer's withdrawal billing units are based on its Actual Energy Withdrawals for all Transmission Service to supply Load in the NYCA, and hourly Energy schedules for all Wheels Through and Exports.

Once there is a final order by FERC regarding the NYISO's ability to recover penalty amounts, the NYISO will include such amounts in the next monthly invoice utilizing the billing units for the month of infraction. For purposes of this calculation, the "month of infraction" is defined as the service month in which the violation occurred. Should the penalty be assessed for a violation occurring over multiple service months, the penalty to be recovered for each service month will be the total penalty to be recovered divided by the number of months over which the violation occurred.

Whenever practicable, the NYISO will recover this charge in the invoice issued in the month following the month in which the NYISO incurs the penalty charge. The NYISO may recover penalty charges over several months if, in its discretion, the NYISO determines such method of recovery to be a prudent course of action. In the event that one or more entities who otherwise would have been apportioned a share of the penalty are no longer Customers, the NYISO will adjust the remaining Customers' shares of the penalty costs, on a proportional basis, if necessary to fully recover the penalty charge.

8.9 ~~Reliability Facilities Charge Recovery~~

~~Placeholder~~

8.9.1   Allocation of Costs Associated with Reliability Facilities Charge

              Placeholder

8.9.2   Recovery of Transmission Owner's Costs Related to Regulated Reliability Transmission Solutions

              Placeholder

8.9.3   Recovery of Costs by an Unregulated Transmitting Utility

              Placeholder

8.9.4   Recovery of Costs Incurred by an Other Developer Related to an Alternative Regulated Solution

              Placeholder

8.10   Recovery of the Highway Facilities Charge

              Placeholder

8.10.1   Recovery of Transmission Owner's Costs Related to Highway System Delivery Upgrades

              Placeholder

8.10.2   Highway Facilities Charge Revenue Requirement Recovery

              Placeholder

8.10.3   Headroom Accounting

              Placeholder

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9. TRANSMISSION CONGESTION CONTRACT SETTLEMENTS

The amount paid or charged to Primary Holders of Transmission Congestion Contracts (TCCs) is computed as the product of (a) the nominal value of the TCC, in megawatts (MW), and (b) the Congestion Component of the LBMP at the Point of Injection for the respective TCC minus the Congestion Component of the LBMP at the Point of Withdrawal for the respective TCC.

The NYISO pays or charges Primary Holders of TCCs for Congestion Rents from revenues collected from (i) Congestion Rents, (ii) Outage/Return-to-Service Congestion Rent Shortfall Charges and Uprate/Derate Congestion Rent Shortfall Charges, and (iii) Net Congestion Rents.

The Congestion payment to Primary TCC Holders is illustrated formulaically in Appendix L of this manual.

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10. TRANSMISSION OWNER SETTLEMENTS

10.1   Net DAM Congestion Rent Balancing

10.1.1   Calculation and Allocation of Net Congestion Rents

10.1.1.1   Calculation of Net Congestion Rents

For each hour of the Day-Ahead Market (DAM), the NYISO settles all Congestion settlements related to the DAM, which include (i) Congestion Rent charges or payments for Energy Transactions in the DAM and Bilateral Transactions scheduled in the DAM; (ii) Congestion payments or charges to Primary Holders of Transmission Congestion Contracts (TCCs); (iii) Outage/Return-to-Service Congestion Rent Shortfall Charges and Uprate/Derate Congestion Rent Shortfall Charges, summed for all Transmission Owners over the hour, as described in Section 10.1.1.3 of this manual; and (iv) Outage/Return-to-Service Congestion Rent Surplus Payments and Uprate/Derate Congestion Rent Surplus Payments, summed for all Transmission Owners over the hour, as described in Section10.1.1.3 of this manual

For each hour of the DAM, the NYISO calculates Net Congestion Rents as Congestion Rent charges or payments for Energy Transactions scheduled in the DAM plus Congestion Rent charges or payments for Bilateral Transactions scheduled in the DAM minus Congestion payments or charges to Primary Holders of TCCs minus Outage/Return-to-Service Congestion Rent Shortfall Charges and Uprate/Derate Congestion Rent Shortfall Charges minus Outage/Return-to-Service Congestion Rent Surplus Payments and Uprate/Derate Congestion Rent Surplus Payments.

10.1.1.2   Allocation of Net Congestion Rents

Hourly Net Congestion Rents are summed over the month and allocated to the Transmission Owners. Positive monthly Net Congestion Rent results in payments to the Transmission Owners, whereas negative balances result in charges to the Transmission Owners. The monthly Net Congestion Rent allocated to each Transmission Owner is computed as the product of (A) the monthly Net Congestion Rent, derived as the sum of the hourly Net Congestion Rents over the month and (B) the quotient of (a) the sum of (i) the Transmission Owner's one-month portion of the revenue imputed to the Direct Sale or the sale in any Centralized TCC Auction sub-auction of Original Residual TCCs that are valid in that month; (ii) sum of the one-month portion of the revenue the Transmission Owner has received as payment for the Direct Sale of ETCNL or for its ETCNL released in the Centralized TCC Auction sub-auction held for TCCs valid for that month; (iii) the one-month portion of the Net Auction Revenues the Transmission Owner has received in Centralized TCC Auction sub-auctions and Reconfiguration Auctions held for TCCs valid for that month, exclusive of any revenue from the sale of Original Residual TCCs; and (iv) the one-month portion of the imputed value of Grandfathered TCCs and Grandfathered Rights, valued at their market clearing prices in the Reconfiguration Auction for that month (or one-sixth of the average market clearing price in stage 1 rounds in the 6-month sub-

auction of the last Centralized TCC Auction if no Reconfiguration Auction was held for that month), provided that the Transmission Owner is the selling party and the Existing Transmission Agreement related to each Grandfathered TCC and Grandfathered Right remains valid in that month; divided by (b) the total revenues for all Transmission Owners received from the sources detailed above in the dividend of this equation for the month. Refer to Section 20.2.5 of the OATT Attachment N for further detail on the computation of the aforementioned variables.

The determination and allocation of Net Congestion Rent is illustrated formulaically in Appendix L of this manual.

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

For each hour of the DAM, the NYISO identifies all constraints that are binding in the Power Flow solution for the final schedules for the hour. For each hour, the NYISO computes the financial impact of each binding constraint and determines whether the constraints are the result of DAM transmission facility outages, returns-to-service, uprates, and/or derates. The NYISO determines to what extent such DAM transmission facility outages, returns-to-service, uprates, and/or derates lead to the creation of the binding constraints and associated Congestion Rent Shortfalls and/or Surpluses. The NYISO charges Transmission Owners for the Congestions Rent Shortfalls and pays Transmission Owners for the Congestion Rent Surpluses attributable to DAM transmission facility outages, returns-to-service, uprates, and derates of the transmission facilities for which they are responsible.

The determination of Congestion Rent Shortfalls and Surpluses attributable to DAM transmission facility outages, returns-to-service, uprates, and derates and the allocation of such Congestion Rent Shortfalls and Surpluses to Transmission Owners are described in detail and formulaically in Section 20.2.4 of Open Access Transmission Tariff (OATT) Attachment N.

10.2 NYPA Transmission Adjustment Charge (NTAC)

Pursuant to Section 7.5 of this manual, the NYISO charges an NTAC to LSEs and Customers scheduling Export or Wheel-Through Transactions not sinking in the New England Control Area. A monthly payment is made to NYPA of the NTAC collected through this charge.

The calculation of the payment of NTAC collected from LSEs and Transmission Customers to NYPA is illustrated formulaically in Appendix K of this manual.

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
OATT Schedule 2: Voltage Support Service Charges	Settlement Details – Load Serving Entity – Ancillary Services

Load Serving Entity Settlements	DSS Report Names
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);
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);

Powers Supplier Settlements	DSS Report Names
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
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

Powers Supplier Settlements	DSS Report Names
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)
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

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Transmission Customer Settlements	DSS Report Names
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
DAM Trading Hub LBMP Energy	Settlement Details - Transaction Customer - Day-Ahead Market Trading Hub LBMP Energy
RT Trading Hub LBMP Energy	Settlement Details - Transaction Customer - Real-Time Market Trading Hub LBMP Energy

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

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

;

Otherwise,

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

> ***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 megawatt basis for Generator g in RTD interval i, expressed in terms of megawatts, as determined below;

- EB_{gi}^{RT} = Generator g's actual megawatt 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 megawatt 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 megawatt 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 megawatt 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*);

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N :   Number of hours in the Dispatch Day

TH_{th}^{DA} :   LBMP Market Energy Import Transaction megawatts 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

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

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 megawatts 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 megawatts 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;

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$LBMPc_{pti}^{RT}$:   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 (FIC) for LBMP Market Energy Imports Failing the NYISO Check-out Process

If Transaction Check -out Failure under MP Control,

$$\text{FIC}_{ti} = \sum_{i=1}^{N} \left(\left(\left(\text{TH}_{ti}^{\text{RTC}} - \text{THC}_{ti}^{\text{RT}} \right) \times s_{ti}^{\text{RT}} \right) \times \max \left(\left(\text{LBMP}_{porti}^{\text{RT}} - \text{LBMP}_{porti}^{\text{RTC}} \right), 0 \right) \right);$$

Otherwise \$0.

$$If\_Transaction\_Check-out\_Failure\_Under\_MP\_Control;\_then$$
$$\sum_{1 \to n}^{N} \left\{ \begin{bmatrix} \left\langle TH_{ti}^{RTC_{15}} - TH_{ti}^{RT} \right\rangle \times s_{i}^{RT} \end{bmatrix} \times \max \\ \begin{bmatrix} \left\langle LBMPe_{porti}^{RT} + LBMPl_{porti}^{RT} - LBMPc_{porti}^{RT} \right\rangle - \left\langle LBMPe_{porti}^{RTC_{15}} + LBMPl_{porti}^{RTC_{15}} - LBMPc_{porti}^{RTC_{15}} \right\rangle, \$0 \end{bmatrix} \right\};$$
$$otherwise\_\$0.$$

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 hours;

$\text{TH}_{ti}^{\text{RTC}}$ $TH_{ti}^{RTC_{15}}$:   LBMP Energy Import Transaction megawatts scheduled by RTC$_{15}$ for hourly transactions and Rolling RTC for intra-hourly transactions containing RTD interval (i) to be imported through Transaction (t), expressed in terms of MW;

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

$\text{LBMP}_{porti}^{\text{RTC}}$ $LBMPe_{porti}^{RTC_{15}}$:   ~~Energy component of the RTC$_{15}$~~RTC 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, for hourly transactions the applicable LBMP from the RTC15 evaluation and for intra-

hourly transactions the LBMP from the Rolling RTC that scheduled the transaction ;

$LBMPl_{porti}^{RTC_{15}}$: ~~Losses component of the RTC₁₅ 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 RTC₁₅ 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.~~

LBMP$_{porti}^{RT}$ $LBMPe_{porti}^{RT}$: ~~Energy component of the Real-Time~~RTD 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.~~

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

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

Incentive payment for Day-Ahead Demand Reduction Providers

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

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 megawatt hours;

$LBMPe_{rh}^{DA}$:   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 megawatt hour 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:

$$\sum_{1\to n}\left\{\begin{array}{l}\left[\max\left\langle\min\left(DRR_{rh}^{RT},DHR_{rh}^{DA}\times 1\_hour\right),0\right\rangle-\left\langle DRH_{rh}^{DA}\times 1\_hour\right\rangle\right]\times\\[2mm]\max\left[\begin{array}{l}\left\{\sum_{i\to}^{N}\left\langle\left(LBMPe_{ri}^{RT}+LBMPl_{ri}^{RT}-LBMPc_{ri}^{RT}\right)\times s_i^{RT}\div 3600\_\sec onds\right\rangle\right\},\\[2mm]\left\{LBMPe_{rh}^{DA}+LBMPl_{rh}^{DA}-LBMPc_{rh}^{DA}\right\}\end{array}\right]\end{array}\right\};$$

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:

$$\sum_{1\to n}^{N}\left\{\begin{array}{l}\left(\max\left\langle\min\left(DRR_{rh}^{RT},DRH_{rh}^{DA}\times 1 hour\right),0\right\rangle-\left\langle DRH_{rh}^{DA}\times 1 hour\right\rangle\right)\times\\[2mm]\left(LBMPe_{rh}^{DA}+LBMPl_{rh}^{DA}-LBMPc_{rh}^{DA}\right)\end{array}\right\},$$

and the Demand Reduction Provider is also charged as follows:

$$\sum_{1\to n}^{N}\left(\begin{array}{l}\left[\begin{array}{l}\left[\max\left\langle\min\left(DRR_{rh}^{RT},DHR_{rh}^{DA}\times 1\_hour\right),0\right\rangle-\left\langle DHR_{rh}^{DA}\times 1\_hour\right\rangle\right]\times\\[2mm]\max\left[\begin{array}{l}\left\{\sum_{i\to n}^{N}\left\langle\left(LBMPe_{ri}^{RT}+LBMPl_{ri}^{RT}-LBMPc_{ri}^{RT}\right)\times s_i^{RT}\div 3600\_\sec onds\right\rangle\right\},\\[2mm]\left\{LBMPe_{rh}^{DA}+LBMPl_{rh}^{DA}-LBMPc_{rh}^{DA}\right\}\end{array}\right]\end{array}\right]-\\[2mm]\left\{\begin{array}{l}\left(\max\left\langle\min\left(DRR_{rh}^{RT},DRH_{rh}^{DA}\times 1\_hour\right),0\right\rangle-\left\langle DRH_{rh}^{DA}\times 1\_hour\right\rangle\right)\times\\[2mm]\left(LBMPe_{rh}^{DA}+LBMPl_{rh}^{DA}-LBMPc_{rh}^{DA}\right)\end{array}\right\}\end{array}\right)$$

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

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

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

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

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

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 megawatts (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:

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	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 megawatt hours 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

Day-Ahead Bid Production Guarantee (DAM BPCG)

The formula for determining the DAM BPCG payments depends upon the total hourly MWs of Bilateral Transactions sourced by the Generator as illustrated below

~~Appendix E.~~   *No Day-Ahead Bilateral Transactions*~~Day-Ahead Bid Production Cost Guarantee Payments (DAM BPCG)~~

Day Ahead Bid Production Cost Guarantee for Generator g

$$= \max\left[\sum_{h=1}^{N}\left\{\int_{MGH_{gh}^{DA}}^{EH_{gh}^{DA}} C_{gh}^{DA} + MGC_{gh}^{DA} MGH_{gh}^{DA} + SUC_{gh}^{DA} NSUH_{gh}^{DA}\right.\right.$$

$$\left.\left. - LBMP_{gh}^{DA}EH_{gh}^{DA} - NASR_{gh}^{DA}\right\}, 0\right]$$

Bilateral Transactions Less Than Day-Ahead Schedule

Day Ahead Bid Production Cost Guarantee for Generator g

$$= \max\left[\sum_{h=1}^{N}\left\{\int_{\max\left(TH_{gh}^{DA}, MGH_{gh}^{DA}\right)}^{EH_{gh}^{DA}} C_{gh}^{DA}\right.\right.$$

$$+ MGC_{gh}^{DA}\min\left(1 - \left(TH_{gh}^{DA} \div MGH_{gh}^{DA}\right), 1\right) - LBMP_{gh}^{DA}\left(EH_{gh}^{DA} - TH_{gh}^{DA}\right)$$

$$\left.\left. - NASR_{gh}^{DA}EH_{gh}^{DA}\right\}, 0\right]$$

Bilateral Transactions Greater Than or Equal to Day-Ahead Schedule

Day Ahead Bid Production Cost Guarantee for Generator $g = 0$

Where:

N :   Number of hours in the Day-Ahead Market Day;

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

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

MGH_{gh}^{DA} : Energy scheduled Day-Ahead to be produced by the minimum generation segment of Generator g in hour h expressed in terms of MWh;

C_{gh}^{DA} : Incremental Energy Bid cost submitted by Generator g, or when applicable the mitigated Incremental Energy Bid cost curve for Generator g, in the Day-Ahead Market for hour h expressed in terms of $/MWh;

MGC_{gh}^{DA} : Minimum Generation Bid by Generator g, or when applicable the mitigated Minimum Generation Bid for Generator g, for hour h in the Day-Ahead Market, expressed in terms of $/MWh.

If Generator g was committed in the Day-Ahead Market, or in the Real-Time Market via Supplemental Resource Evaluation (SRE), on the day prior to the Dispatch Day and Generator g has not yet completed the minimum run time reflected in the accepted Bid for the hour in which it was scheduled to start on the day before the Dispatch Day (as mitigated, where appropriate), then Generator g shall have its minimum generation cost set equal to the revenues received for energy produced at its minimum operating level for purposes of calculating a Day-Ahead Bid Production Cost guarantee until Generator g completes the minimum run time reflected in the accepted Bid for the hour in which it was scheduled to start on the day before the Dispatch Day;

SUC_{gh}^{DA} : Start-Up Bid by Generator g in hour h, or when applicable the mitigated Start-Up Bid for Generator g in hour h, in the Day-Ahead Market expressed in terms of $/start; *provided, however,* that the Start-Up Bid for Generator g in hour h or, when applicable, the mitigated Start-Up Bid, for Generator g in hour h, may be subject to pro rata reduction in accordance with the rules illustrated formulaically below in this Appendix. Bases for pro rata reduction include, but are not limited to, failure to be scheduled, and to operate in real-time to produce, in each hour, the MWh specified in the accepted Minimum Generation Bid that was submitted for the first hour of Generator g's Day-Ahead or SRE schedule, and failure to operate for the minimum run time specified in the Bid submitted for the first hour of Generator g's Day-Ahead or SRE schedule.

If a Generator g was committed in the Day-Ahead Market, or in the Real-Time Market via SRE, on the day prior to the Dispatch Day, and Generator g has not yet completed the minimum run time reflected in the accepted Bid for the hour in which it was scheduled to start on the day before the Dispatch Day (as mitigated, where appropriate) plus the contiguous hour that follows the conclusion of such minimum run time, then Generator g shall have its Start-Up Bid set to zero for purposes of calculating a Day-Ahead Bid Production Cost guarantee.

For a long start-up time Generator (i.e., a Generator that cannot be scheduled by SCUC to start up in time for the next Dispatch Day) that is committed by the NYISO and runs in real-time, the Start-Up Bid for Generator g in hour h shall be the Generator's Start-Up Bid, or when applicable the mitigated Start-Up Bid for Generator g, for the hour (as determined at the point in time in which the NYISO provided notice of the request for start-up);

$NSUH_{gh}^{DA}$: Number of times Generator g is scheduled Day-Ahead to start up in hour h;

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

NASR_{gh}^{DA} : Net Ancillary Services revenue, expressed in terms of $, paid to Generator g as a result of having been committed to produce Energy for the LBMP Market and/or Ancillary Services Day-Ahead in hour h which is computed by summing the following: (1) Voltage Support Service payments received by that Generator for that hour, if it is not a Supplier of Installed Capacity and has been scheduled to operate in that hour; (2) Regulation Service payments made to that Generator for all Regulation Service it is scheduled Day-Ahead to provide in that hour, less that Generator's Day-Ahead Bid to provide that amount of Regulation Service in that hour (unless the Bid exceed the payments that Generator receives for providing Regulation Service that was committed to produce Energy for the LBMP Market and/or Ancillary Services Day-Ahead, in which case this component shall be zero); (3) payments made to that Generator for providing Spinning Reserve and synchronized 30-Minute Reserve in that hour if it is committed Day-Ahead to provide such reserves in that hour, less that Generator's Day-Ahead Bid to provide Spinning Reserve and synchronized 30-Minute Reserve in that hour.

Total Energy Required to be Provided in Order to Avoid Proration of a Generator's Start-Up Costs

$$\text{TotMWReq}_{g,s} = \text{MinOpMW}_{g,s} \times n_{g,s}$$

Where:

$\text{TotMWReq}_{g,s}$ = Total amount of Energy that Generator g, when started in hour s, must provide for its start-up costs not to be prorated;

$\text{MinOpMW}_{g,s}$ = Minimum operating level (in MW) specified by Generator g in its hour s Bid;

$n_{g,s}$ = The last hour that Generator g must operate when started in hour s to complete both its minimum run time and its Day-Ahead schedule. The variable $n_{g,s}$ is calculated as follows:

$$n_{g,s} = \max\left(\text{LastHrDASched}_{g,s}, \text{LastMinRunHr}_{g,s}\right)$$

Where:

$\text{LastHrDASched}_{g,s}$ = The last date/hour in a contiguous set of hours in the Dispatch Day, beginning with hour s, in which Generator g is scheduled to operate in the Day-Ahead Market;

$\text{LastMinRunHr}_{g,s}$ = The last date/hour in a contiguous set of hours in which Generator g would need to operate to complete its minimum run time if it starts in hour s.

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Calculation of Prorated Start-Up Cost

$$\text{ProratedSUC}_{gs} = \text{SubmittedSUC}_{gs}$$

$$= \times \left(\sum_{h=s}^{n_{gs}} \text{MinOpEnergy}_{ghs} \div \text{TotalMWReq}_{gs} \right)$$

Where:

$\text{ProratedSUC}_{g,s}$ = the prorated start-up cost used to calculate the Bid Production Cost guarantee for Generator g that is scheduled to start in hour s;

$\text{SubmittedSUC}_{g,s}$ = The Start-Up Bid submitted (as mitigated where appropriate) for Generator g that is scheduled to start in hour s;

$\text{MinOptEnergy}_{g,h,s}$ = the amount of Energy produced during hour h by Generator g during the time required to complete both its minimum run time and its Day-Ahead schedule, if that generator started in hour s.

$\text{MinOpEnergy}_{g,h,s}$ is calculated as follows:

$$\text{MinOpEnergy}_{ghs} = \min \left(\text{MetActEnergy}_{gh}, \quad \text{MinOpMW}_{gs} \right)$$

Where:

MetActEnergy_{gh} = the metered amount of Energy produced by Generator g during hour h.

Additional Rules that Apply to the Calculation of Prorated Start-Up Cost

1. **For any hour that a Generator is derated below the minimum operating level specified in its accepted Start-Up Bid for reliability, either by the NYISO or at the request of a Transmission Owner, the Generator will receive credit for that hour as if the Generator had produced metered actual MWh equal to its MinOpMW_{gs}.**

2. **A Generator must be scheduled and operate in real-time to produce Energy consistent with the MinOpMW_{gs}. specified in the accepted Start-Up Bid for each hour that it is expected to run. These rules do not specify or require any particular bidding construct that must be used to achieve the desired commitment. However, submitting a self-committed bid may preclude a Generator form receiving a BPCG.** $\overline{} EI^{RT}_{gs} \quad EI_{gs} \qquad \text{RT} \; EI^{RT}_{gs}\text{DA}$

Formula for Determining Real-Time BPCG for Generators in RTD Intervals Other Than Supplemental Event Intervals

Real − Time Bid Production Cost Guarantee for Generator g

$$
= \max\left[\left(\sum_{i \in M}\left(\left(\int_{\max\left(EI_{gi}^{DA},MGI_{gi}^{RT}\right)}^{\max\left(EI_{gi}^{RT},MGI_{gi}^{RT}\right)} C_{gi}^{RT} + MGC_{gi}^{RT} \times \left(MGI_{gi}^{RT} - MGI_{gi}^{DA}\right)\right.\right.\right.\right.
$$

$$
- LBMP_{gi}^{RT} \times \left(EI_{gi}^{RT} - EI_{gi}^{DA}\right) - \left(NASR_{gi}^{TOT} - NASR_{gi}^{DA}\right) - RRAP_{gi}
$$

$$
\left.\left.\left.\left. + RRAC_{gi}\right) \times (s_i \div 3600)\right) + \sum_{j \in L} SUC_{gi}^{RT} \times \left(NSUI_{gi}^{RT} - NSUI_{gi}^{DA}\right)\right), 0\right]
$$

Where:

S_i = number of seconds in RTD interval i;

C_{gi}^{RT} = Bid cost submitted by Generator g, or when applicable the mitigated Bid cost for

Generator g, in the RTD for the hour that includes RTD interval i expressed in terms of
$/MWh, except in intervals in which the dispatch of the Generator is constrained by its

downward ramp rate for that interval, unless that Generator was scheduled to provide

Regulation Service in that interval and its RTD basepoint was less than its AGC basepoint,

and except in hours in which the NYISO has increased Generator g's minimum operating

level, either (i) at the Generator's request, or (ii) in order to reconcile the ISO's dispatch

with the Generator's actual output or to address reliability concerns that arise because the

Generator is not following Base Point Signals, in which case C_{gi}^{RT} shall be deemed to be

zero;

MGI_{gi}^{RT} = metered Energy produced by minimum generation segment of Generator g

in RTD interval i expressed in terms of MW;

MGI_{gi}^{DA} = Energy scheduled Day-Ahead to be produced by minimum generation segment of Generator g in RTD interval i expressed in terms of MW;

MGC_{gi}^{RT} = Minimum Generation Bid by Generator g, or when applicable the mitigated Minimum Generation Bid for Generator g, in the Real-Time Market for the hour that includes RTD interval i, expressed in terms of $/MWh, which Bid or mitigated Bid may include costs pursuant to Section 4.1.8 of the NYISO Services Tariff;

If Generator g was committed in the Day-Ahead Market, or in the Real-Time Market via Supplemental Resource Evaluation ("SRE"), on the day prior to the Dispatch Day *and* Generator g has not yet completed the minimum run time reflected in the accepted Bid for the hour in which it was scheduled to start on the day before the Dispatch Day (as mitigated, where appropriate), *then* Generator g shall have its minimum generation cost set equal to the revenues received for energy produced at its minimum operating level for purposes of calculating a Real-Time Bid Production Cost guarantee until Generator g completes the minimum run time reflected in the accepted Bid for the hour in which it was scheduled to start on the day before the Dispatch Day;

SUC_{gi}^{RT} = Start-Up Bid by Generator g, or when applicable the mitigated Start-Up Bid for Generator g, for hour j into RTD expressed in terms of $/start, which Bid or mitigated Bid may include costs pursuant to Section 4.1.8 of the NYISO Services Tariff;

provided, however,

(i) the Start-Up Bid shall be deemed to be zero for (1) Self-Committed Fixed and Self-Committed Flexible Generators, (2) Generators that are economically committed by RTC or RTD that have 10-minute start-up times that are not synchronized and producing Energy within 20 minutes after their scheduled start time, and (3) Generators that are economically committed by RTC that have greater than 10-minute start-up times that are

not synchronized and producing Energy within 45 minutes after their scheduled start time;

(ii) if a Generator has been committed via SRE and its SRE schedule immediately precedes or follows a real-time commitment that did not result from a Day-Ahead commitment, the Generator's Start-Up Bid included in its daily real-time Bid Production Cost guarantee calculation for this contiguous real-time commitment period shall be the Start-Up Bid submitted in response to the SRE request (subject to mitigation, where appropriate);

(iii) if a Generator has been committed via SRE and its SRE schedule immediately precedes or follows a real-time schedule that resulted from a Day-Ahead commitment, then the Generator's Start-Up Bid included in its daily real-time Bid Production Cost guarantee calculation for this contiguous real-time commitment period shall be set to zero;

(iv) the real-time Start-Up Bid for Generator g for hour j or, when applicable, the mitigated real-time Start-Up Bid, for Generator g for hour j, may be subject to *pro rata* reduction in accordance with the rules illustrated formulaically in this Appendix E. Bases for *pro rata* reduction include, but are not limited to, failure to be scheduled and operate in real-time to produce, in each hour, the MWh specified in the accepted Minimum Generation Bid that was submitted for the first hour of Generator g's Day-Ahead or SRE schedule, and failure to operate for the minimum run time specified in the Bid submitted for the first hour of Generator g's Day-Ahead or SRE schedule; and

(v) if Generator g was committed in the Day-Ahead Market, or in the Real-Time Market via SRE, on the day prior to the Dispatch Day, *and* Generator g has not yet completed the minimum run time reflected in the accepted Bid for the hour in which it was scheduled to start on the day before the Dispatch Day (as mitigated, where appropriate) plus the contiguous hour that follows the conclusion of such minimum run time, *then* Generator g shall have its Start-Up Bid set to zero for purposes of calculating a Real-Time Bid Production Cost guarantee;

$NSUI_{gj}^{RT}$ = number of times Generator g started up in hour j;

$NSUI_{gj}^{DA}$ = number of times Generator g is scheduled Day-Ahead to start up in hour j;

$LBMP_{gi}^{RT}$ = Real-Time LBMP at Generator g's bus in RTD interval i expressed in terms of $/MWh;

M = the set of eligible RTD intervals in the Dispatch Day consisting of all of the RTD intervals in the Dispatch Day except:

(i) Supplemental Event Intervals (which are addressed separately in Appendix E below);

(ii) intervals during authorized Start-Up Periods, Shutdown Periods, or Testing Periods for Generator g;

L = the set of all hours in the Dispatch Day;

EI_{gi}^{RT} = either, as the case may be:

(i) if $EOP_{ig} > AEI_{ig}$ then $\min(\max(AEI_{ig}, RTSen_{ig}), EOP_{ig})$; or

(ii) if otherwise, then $\max(\min(AEI_{ig}, RTSen_{ig}), EOP_{ig})$;

TH_{gi}^{RT} = Bilateral Transactions scheduled real-time to be sourced by Generator g in hour h in terms of MW;

TH_{gi}^{DA} = Bilateral Transactions scheduled Day-Ahead to be sourced by Generator g in hour h in terms of MW;

EI_{gi}^{DA} = Energy scheduled in the Day-Ahead Market to be produced by Generator g in the hour that includes RTD interval i expressed in terms of MW, plus the greater of (a) TH_{gi}^{RT} minus TH_{gi}^{DA} and (b) zero;

$RTSen_{ig}$ = Real-time Energy scheduled for Generator g in interval i, and

calculated as the arithmetic average of the 6-second AGC Base Point Signals sent to Generator g during the course of interval i expressed in terms of MW;

AEI_{ig} = average Actual Energy Injection by Generator g in interval i but not more than $RTSen_{ig}$ plus any Compensable Overgeneration expressed in terms of MW;

EOP_{ig} = the Economic Operating Point of Generator g in interval i expressed in terms of MW;

$NASR_{gi}^{TOT}$ = Net Ancillary Services revenue, expressed in terms of $, paid to Generator g as a result of either having been committed Day-Ahead to operate in the hour that includes RTD interval i or having operated in interval i which is computed by summing the following: (1) Voltage Support Service payments received by that Generator for that RTD interval, if it is not a Supplier of Installed Capacity; (2) Regulation Service payments that would be made to that Generator for that hour based on a Performance Index of 1, less the Bid(s) placed by that Generator to provide Regulation Service in that hour at the time it was committed to produce Energy for the LBMP Market and/or Ancillary Services to do so (unless the Bid(s) exceeds the payments that Generator receives for providing Regulation Service, in which case this component shall be zero); (3) payments made to that Generator for providing Spinning Reserve or synchronized 30-Minute Reserve in that hour, less the Bid placed by that Generator to provide such reserves in that hour at the time it was scheduled to do so; and (4) Lost Opportunity Cost payments made to that Generator in that hour as a result of reducing that Generator's output in order for it to provide Voltage Support Service;

$NASR_{gi}^{DA}$ = The proportion of the Day-Ahead net Ancillary Services revenue, expressed in terms of $, that is applicable to interval i calculated by multiplying the $NASR_{gh}^{DA}$ for the hour that includes interval i by Si/3600;

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RRAP$_{gi}$ = Regulation Revenue Adjustment Payment for Generator g in RTD interval i expressed in terms of $;

RRAC$_{gi}$ = Regulation Revenue Adjustment Charge for Generator g in RTD interval i expressed in terms of $.

Formula for Determining Real-Time BPCG for Generators in Supplemental Event Intervals

Real − Time Bid Production Cost Guarantee Payment for Generator g

$$
= \sum_{i \in P} \left(\max \left(\left(\int_{\max\left(EI_{gi}^{DA},MGI_{gi}^{RT}\right)}^{\max\left(EI_{gi}^{RT},MGI_{gi}^{RT}\right)} C_{gi}^{RT} + MGC_{gi}^{RT} \times \left(MGI_{gi}^{RT} - MGI_{gi}^{DA}\right) \right. \right. \right.
$$
$$
\left. - LBMP_{gi}^{RT} \times \left(EI_{gi}^{RT} - EI_{gi}^{DA}\right) - \left(NASR_{gi}^{TOT} - NASR_{gi}^{DA}\right) - RRAP_{gi} \right.
$$
$$
\left. \left. \left. + RRAC_{gi} \right) \times (s_i \div 3600) \right), 0 \right)
$$

Where:

P = the set of Supplemental Event Intervals in the Dispatch Day but excluding any intervals in which there are maximum generation pickups or large event reserve pickups where EI_{gi}^{RT} is less than or equal to EI_{gi}^{DA}; and

EI_{gi}^{RT} = (i) for any intervals in which there are maximum generation pickups, and the three intervals following, for Generators in the location for which the maximum generation pickup has been called -- the average Actual Energy Injections, expressed in MWh, for Generator g in interval i, and for all other Generators EI_{gi}^{RT} is as defined in the formula for Real-Time BPCG for RTD Intervals Other Than Supplemental Event Intervals above.

(ii) for any intervals in which there are large event reserve pickups and the three intervals following, EI_{gi}^{RT} is as defined in the formula for Real-Time BPCG for RTD Intervals Other Than Supplemental Event Intervals above.

C_{gi}^{RT} = Bid cost submitted by Generator g, or when applicable the mitigated Bid cost for Generator g, in the RTD for the hour that includes RTD interval i expressed in terms of $/MWh, except in hours in which the NYISO has increased Generator g's minimum operating level, either (i) at the Generator's request, or (ii) in order to reconcile the NYISO's dispatch with the Generator's actual output or to address reliability concerns that arise because the Generator is not following Base Point Signals, in which case C_{gi}^{RT} shall be deemed to be zero;

The definition of all other variables is identical to those defined in the formula for Real-Time BPCG for RTD Intervals Other Than Supplemental Event Intervals above.

Bids Used For Intervals at the End of the Hour

For RTD intervals in an hour that start 55 minutes or later after the start of that hour, a Bid used to determine real-time BPCG above will be the Bid for the next hour in accordance with ISO Procedures. For RTD-CAM intervals in an hour that start 50 minutes or later after the start of that hour, a Bid used to determine real-time BPCG above will be the Bid for the next hour, in accordance with ISO Procedures.

Day-Ahead BPCG for LBMP Market Energy Imports

Day − Ahead Bid Production Cost guarantee for Import t by Supplier

$$= \max\left(\sum_{h=1}^{N}\left(DecBid_{th}^{DA} - LBMP_{th}^{DA}\right) \times SchImport_{th}^{DA}, 0\right)$$

Where:

N = number of hours in the Day-Ahead Market day;

$DecBid_{th}^{DA}$ = Decremental Bid, in $/MWh, supplied for Import t for hour h;

$LBMP_{th}^{DA}$ = Day-Ahead LBMP, in $/MWh, for hour h at the Proxy Generator Bus that is the source of the Import t; and

$SchImport_{th}^{DA}$ = total Day-Ahead schedule, in MWh, for Import t in hour h.

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Real-Time BPCG for LBMP Energy Market Imports

Real $-$ Time Bid Production Cost Guarantee for Import t by a Supplier

$$
= \text{Max} \left(\sum_{i=1}^{Q} \left(\left(\text{DecBid}_{ti}^{RT} - \text{LBMP}_{ti}^{RT} \right) \times \max \left(\text{SchImport}_{ti}^{RT} - \text{SchImport}_{ti}^{DA}, 0 \right) \right. \right.
$$

$$
\left. \left. \times s_i \div 3600 \right), 0 \right)
$$

Where:

Q = number of intervals in the Dispatch Day;

DecBid_{ti}^{RT} = Decremental Bid, in \$/MWh, supplied for Import t for interval i;

LBMP_{ti}^{RT} = real-time LBMP, in \$/MWh, for interval i at Proxy Generator Bus p which is the source of the Import t;

$\text{SchImport}_{ti}^{RT}$ = total real-time schedule, in MW, for Import t in interval i;

$\text{SchImport}_{ti}^{DA}$ = total Day-Ahead schedule, in MW, for Import t in hour that contains interval I;

s_i = number of seconds in RTD interval i.

Day-Ahead BPCG for Demand Reduction

Day $-$ Ahead BPCG for Demand Reduction Provider d

$$
= \text{Max} \left(\sum_{h=1}^{N} \left(\text{MinCurCost}_d^h + \text{IncrCurCost}_d^h - \text{CurRev}_d^h \right) + \text{CurInitCost}_d, 0 \right)
$$

Where:

$\text{CurInitCost}_d = \left(\sum_{h=1}^{N} \left(\text{Min} \left(\text{ActCur}_d^h, \text{SchdCur}_d^h \right) \right) \div \left(\sum_{h=1}^{N} \text{SchdCur}_d^h \right) \right) \times \text{CurCost}_d$

$\text{MinCurCost}_d^h = \text{Min} \left(\left(\max \left(\text{Actcur}_d^h, 0 \right), \text{MinCur}_d^h \right) \right) \times \text{MinCurBid}_{d}^h;$

$\text{IncrCurCost}_d^h = \int_{\text{MinCur}_d^h}^{\max \left(\text{MinCur}_d^h, \min \left(\text{SchdCur}_d^h, \text{ActCur}_d^h \right) \right)} \text{IncrCurBid}_{d}^h;$

$$CurRev_d^h = LBMP_{dh}^{DA} \times \min\left(\max\left(ActCur_d^h, 0\right), SchdCur_d^h\right);$$

N = number of hours in the Day-Ahead Market day;

$CurInitCost_d$ = daily Curtailment Initiation Cost credit for Day-Ahead Demand Reduction Provider d;

$MinCurCost_h^h$ = minimum Curtailment cost credit for Day-Ahead Demand Reduction Provider d in hour h;

$IncrCurCost_d^h$ = incremental Curtailment cost credit for Day-Ahead Demand Reduction Provider d for hour h;

$CurCost_d$ = total bid Curtailment Initiation Costs for Day-Ahead Demand Reduction Provider d for the day;

$CurRev_d^h$ = actual revenue for Day-Ahead Demand Reduction Provider d in hour h;

$ActCur_h^d$ = actual Energy curtailed by Day-Ahead Demand Reduction Provider d in hour h expressed in terms of MWh;

$SchdCur_h^d$ = Energy scheduled Day-Ahead to be curtailed by Day-Ahead Demand Reduction Provider d in hour h expressed in terms of MWh;

$MinCurBid_h^d$ = minimum Curtailment initiation Bid submitted by Day-Ahead Demand Reduction Provider d for hour h expressed in terms of $/MWh;

$IncrCurBid_h^d$ = Bid cost submitted by Day-Ahead Demand Reduction Provider d for hour h expressed in terms of $/MWh;

$MinCur_h^d$ = Energy scheduled Day-Ahead to be produced by the minimum Curtailment segment of Day-Ahead Demand Reduction Provider d for hour h expressed in terms of MWh; and

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LBMP_{dh}^{DA} = Day-Ahead LBMP for Day-Ahead Demand Reduction Provider d for hour h expressed in $/MWh.

Day-Ahead BPCG for Demand Side Resources Providing Synchronized Operating Reserves

BPCG for Demand Side Resource d Providing synchronized Operating Reserves Day − Ahead

$$= \max \left(\left(- \sum_{h=1}^{N} \text{NASR}_{dh}^{DA} \right), 0 \right)$$

Where:

N = number of hours in the Day-Ahead Market day;

NASR_{dh}^{DA} = Net Ancillary Services revenue, in $, paid to Demand Side Resource d as a result of having been committed to provide Ancillary Services Day-Ahead in hour h which is computed by summing the following: (1) Regulation Service payments made to that Demand Side Resource for all Regulation Service it is scheduled Day-Ahead to provide in that hour, less Demand Side Resource d's Day-Ahead Bid to provide that amount of Regulation Service in that hour (unless the Bid exceeds the payments that the Demand Side Resource receives for providing Regulation Service that was committed to provide Ancillary Services Day-Ahead, in which case this component shall be zero); and (2) payments made to Demand Side Resource d for providing Spinning Reserve and synchronized 30-Minute Reserve in that hour if it is committed Day-Ahead to provide such reserves, hour, less Demand Side Resource d's Day-Ahead Bid to provide Spinning Reserve and synchronized 30-Minute Reserve in that hour.

Real-Time BPCG for Demand Side Resources Providing Synchronized Operating Reserves

BPCG for Demand Side Resource d Providing synchronized Operating Reserves in Real − Time

$$= \max \left(- \sum_{i \in L} \left(\text{NASR}_{di}^{TOT} - \text{NASR}_{di}^{DA} \right), 0 \right)$$

Where:

L = set of RTD intervals in the Dispatch Day;

NASR_{di}^{TOT} = Net Ancillary Services revenue, in $, paid to Demand Side Resource d as a

result of either having been scheduled Day-Ahead in the hour that includes RTD interval i or having been scheduled in real-time interval i which is computed by summing the following: (1) Regulation Service payments that would be made to Demand Side Resource d for that hour based on a Performance Index of 1, less the Bid(s) placed by Demand Side Resource d to provide Regulation Service in that hour at the time it was committed to provide Ancillary Services (unless the Bid(s) exceeds the payments that Demand Side Resource d receives for providing Regulation Service, in which case this component shall be zero); and (2) payments made to Demand Side Resource d for providing Spinning Reserve or Synchronized 30-Minute Reserve in that hour, less the Bid placed by Demand Side Resource d to provide such reserves in that hour at the time it was scheduled to do so; and

$NASR_{di}^{DA}$= The proportion of the Day-Ahead net Ancillary Services revenue, in $, that is applicable to interval i calculated by multiplying the $NASR_{dh}^{DA}$ for the hour that includes interval i by the quotient of the number of seconds in RTD interval i divided by 3600.

Import Curtailment Guarantee Payment for a Supplier Whose Import Was Curtailed by the ISO

Import Curtailment Guarantee Payment to Supplier u in association with Import t

$$= \max\left(\left(RTLBMP_{ti} - \max(DADecBid_{ti}, 0)\right) \times (DAen_{ti} - RTDen_{ti}) \times s_i \div 3600, 0\right)$$

Where:

i = the relevant interval;

s_i = number of seconds in interval i;

$RTLBMP_{ti}$ = the real-time LBMP, in $/MWh, for interval i at the Proxy Generator Bus which is the source of the Import t;

$DADecBid_{ti}$= the Day Ahead Decremental Bid price associated with the Day-Ahead energy schedule, in $/MWh, for Import t in hour h containing interval i;

$DAen_{ti}$= the Day Ahead scheduled Energy injections, in MWh, for Import t in hour h containing interval i as determined by Security Constrained Unit Commitment (SCUC); and

$RTDen_{ti}$= the scheduled Energy injections, in MWh, for Import t in interval i as determined by Real-Time Dispatch (RTD).

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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 ($/MWh)* in the diagram below, is less than the cost component of the first point on a Generator's Bid curve, depicted as P_1 in the diagram below, then the Generator's EOP is equal to the megawatt component of the first point on the Generator's cost curve (i.e., Q_1).
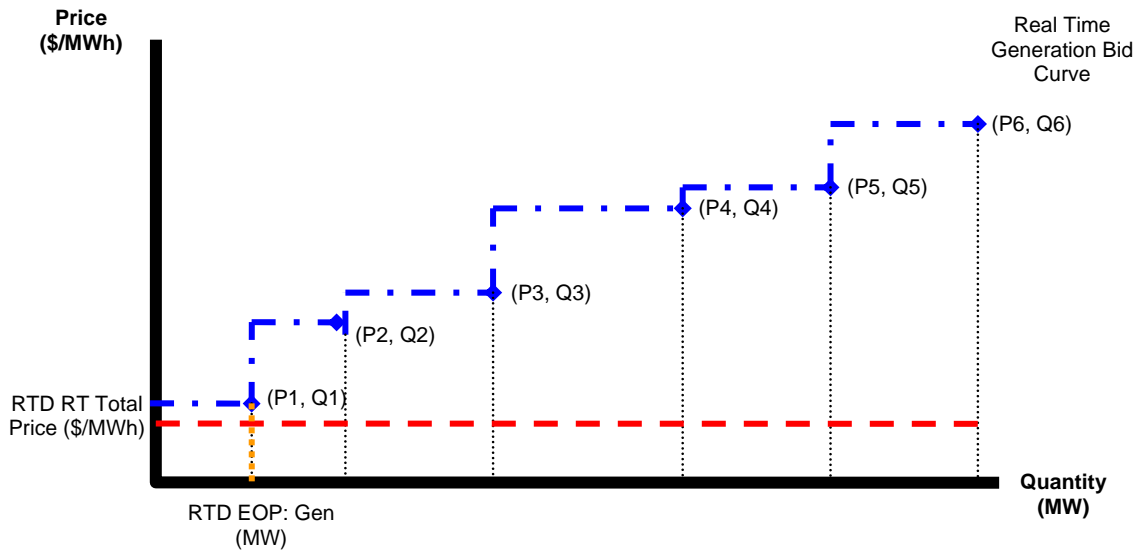
If the RTD interval LBMP (i.e., *RTD RT Total Price ($/MWh)*) is greater than the cost component of the last point on a Generator's Bid curve, depicted as P_6 in the diagram below, then the Generator's EOP is equal to the megawatt component of the last point on the its cost curve (i,e,. Q_6).
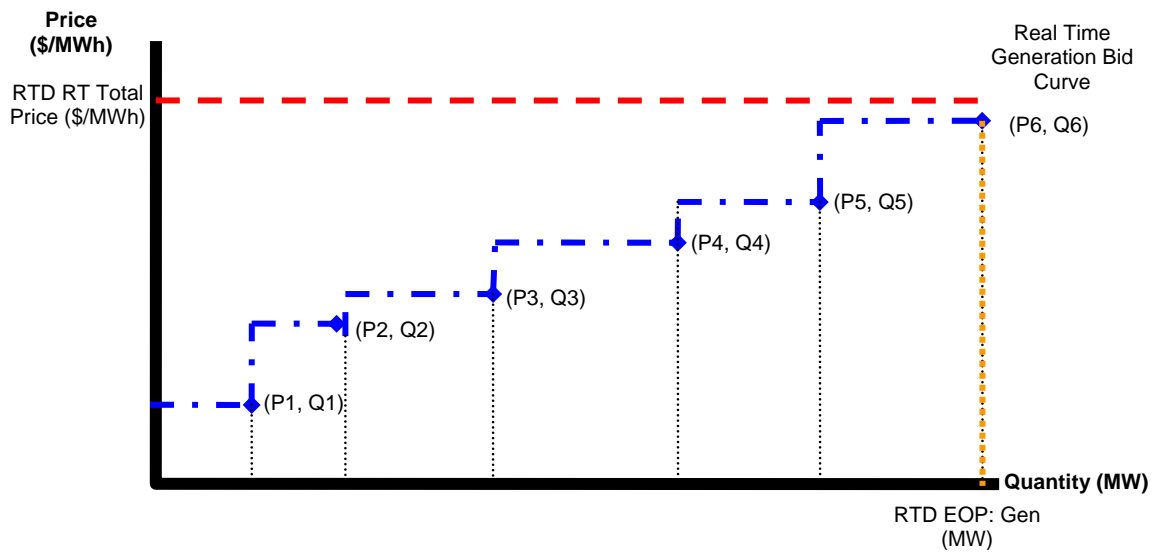
If the RTD interval LBMP is greater than or equal to the cost component of the first point on a Generator's Bid curve (i.e., P_1) and less or equal to the cost component of the last point on the unit's cost curve (i,e,. P_6), then in order to determine a Generator's EOP the Generation Bid block that 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 megawatt value of the given block (i.e., Q_3).
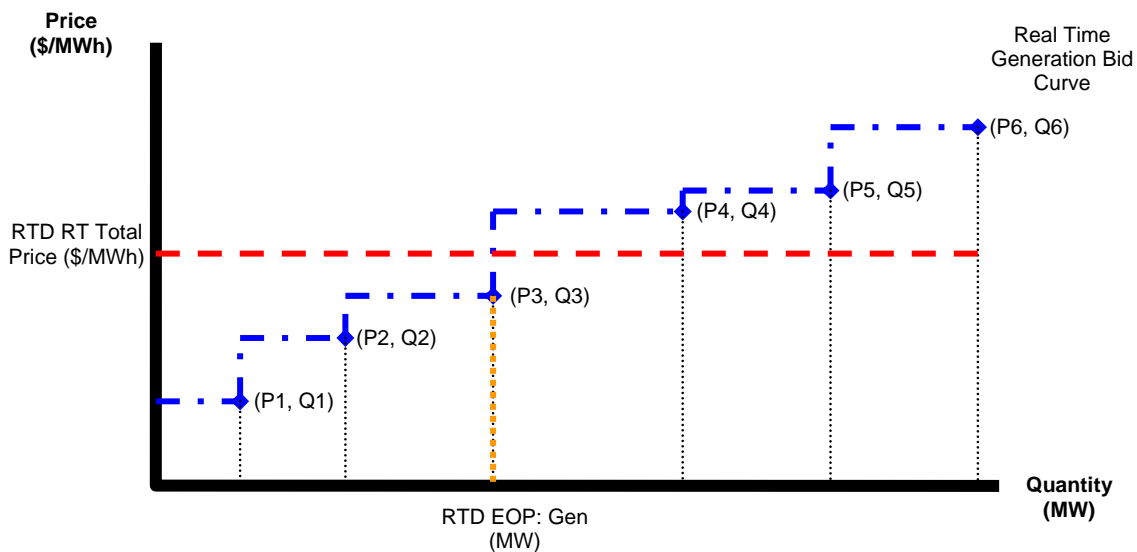
If the RTD interval LBMP intersects the given Generation Bid block on a horizontal line and the Generator's RTD Base Point is greater than the megawatt component of the last point on the Generator's bid curve, as in the diagram below, then the Generator's EOP is equal the its RTD Base Point.
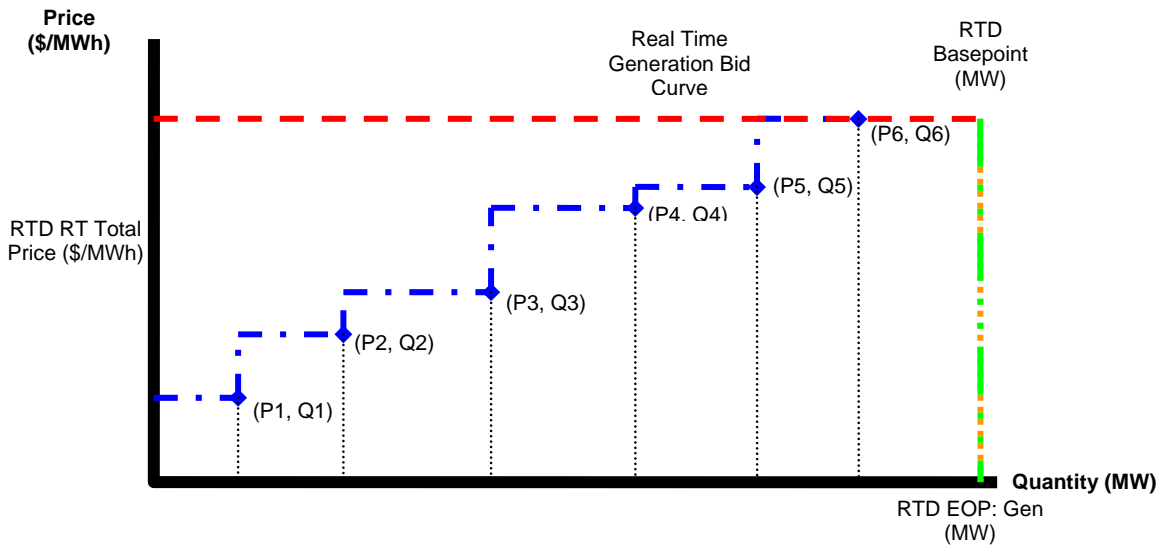
Similarly, if the RTD interval LBMP intersects the given Generation Bid block on a horizontal line and the Generator was Base Pointed within the same bid block, the Generator's EOP is equal to its RTD Base Point.
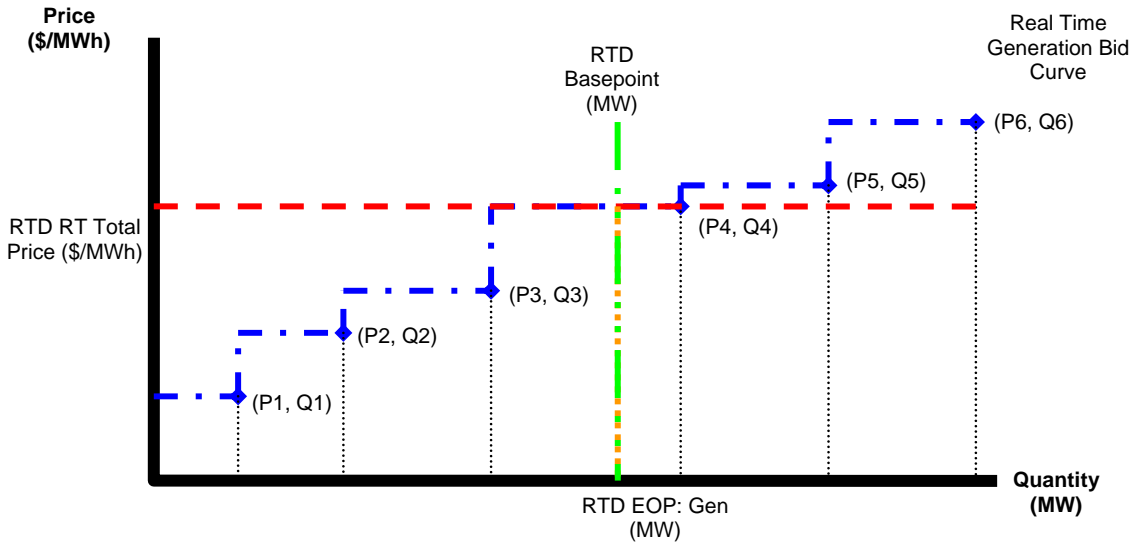
In the diagram below, however, the RTD interval LBMP intersects the given Generation Bid block on a horizontal line; however, the Generator was Base Pointed beyond its economics. In this case, the Generator's EOP is equal to the higher Generation Block MW (i.e., Q_4) of the block where the RTD interval LBMP intersects the Generation Bid.
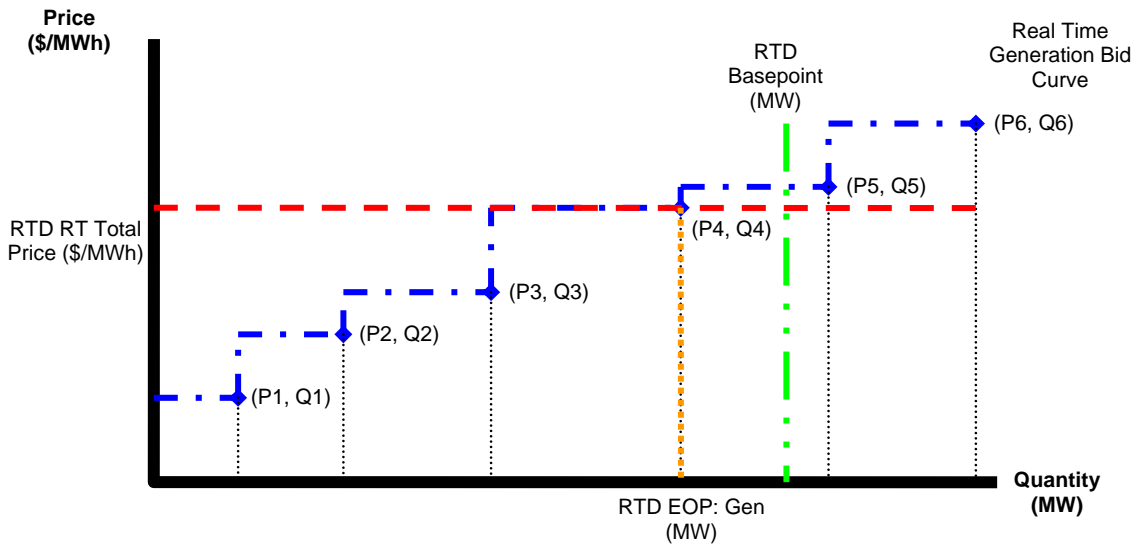
In the diagram below, the RTD interval LBMP intersects the given Generation Bid block on a horizontal line and the Generator was Base Pointed below the given Generation Bid block. In this case, the Generator's EOP is equal to the lower Generation Block MW (i.e., Q_3) of the block where the RTD interval LBMP intersects the Generation Bid.
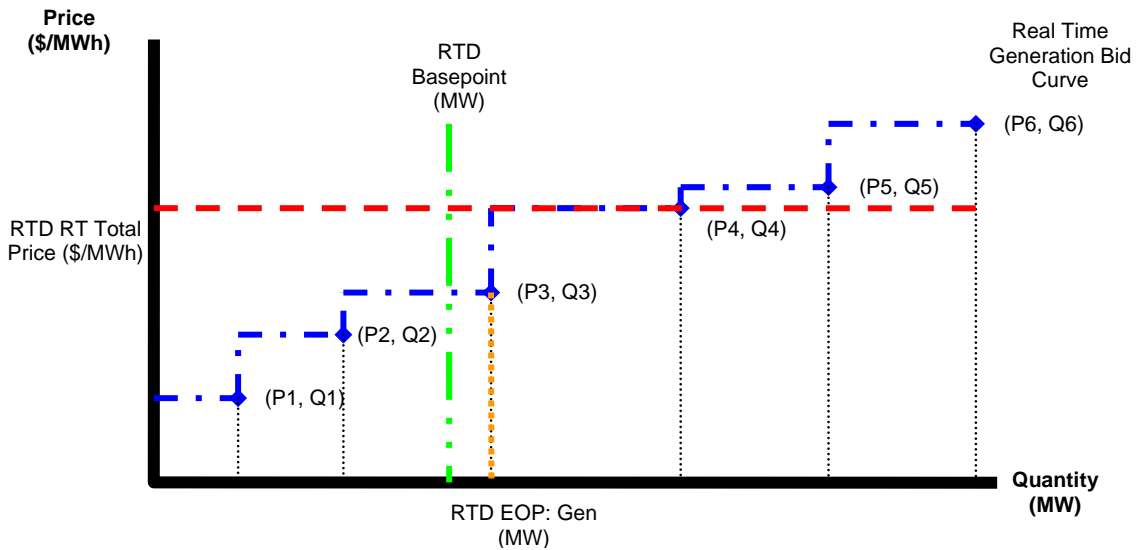
Appendix G.   Real-Time Performance Tracking

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}

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

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 megawatts [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., $AGC_{gs\,\min}^{RT} = \min\limits_{s=1}^{5} AGC_{gs}^{RT}$). 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.,

$$PCE_{gi}^{RT} = \left\{ \sum_{x=1}^{n} PCE_{g30}^{RT} \right\} \div n \text{)};$$

> **Where:**

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

> $AGC_{gs\,\max}^{RT}$: 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_{g30}^{RT} : 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 $Pi\,\mathrm{Re}\,g_{gi}^{RT}$

$$If\_i = OR\{i_{RPU}, i_{RPU+1}, i_{RPU+2}, i_{RPU+3}\},\_then\_Pi\,\mathrm{Re}\,g_{gi}^{RT} = 1;\_otherwise,$$
$$Pi\,\mathrm{Re}\,g_{gi}^{RT} = \min\left\{\left[\left(REG_{gi}^{RT} - \left(PCE_{gi}^{RT} + NCE_{gi}^{RT}\right)\right] \div REG_{gi}^{RT}\right) + 0.10, 1\right\} \times \left\{RGPD \div s_i\right\},$$

> **Where:**

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

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

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

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

$$If\_SRD_{di}^{RT} = 0,\_then\_Pi\,\mathrm{Re}\,s_{gi}^{RT} = 1;\_otherwise,$$
$$Pi\,\mathrm{Re}\,s_{gi}^{RT} = \max\left[\min\left\{\left(ADR_{di}^{RT} \div SDR_{di}^{RT}\right) + 0.1, 1\right\}, 0\right]$$,

Where:

d :   Demand Side Resource (d);

i :   RTD interval (i);

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

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

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Appendix H.   DAM Margin Assurance Payments (DAMAP)

Day-Ahead Margin Assurance Payments (DAMAP) to Generators and Demand Side Resources are determined through the equations illustrated formulaically in this appendix and described in Section 4.1.5 of this manual. Definitions of the variables used in the following equations are provided at the end of this appendix.

Hourly DAMAP for Generators

$$DAMP_{hu} = \max\left\{0, \sum_{i \in h} CDAMP_{iu}\right\}$$

> *Where:*

$$CDAMP_{iu} = CDAMPen_{iu} + \sum_{p} CDAM\Pr es_{iup} + CDAM\Pr eg_{iu}$$

RTD Interval Energy Component of DAMAP When Eligible Generators' Real-Time Energy Schedules are Less Than Their DAM Energy Schedules

$$CDAMPen_{iu} = If \begin{cases} AND\left(RTSen_{iu} \prec DASen_{hu}, EOP_{iu} \succ RTSen_{iu}\right), \\ \left[\left[DASen_{hu} - \min\left\langle \max\left\{RTSen_{iu}, \min\left(AEI_{iu,}EOP_{iu}\right)\right\}, DASen_{hu}\right\rangle\right] \times RTPen_{iu}\right) - \\ \int_{\min\left\langle \max\left\{RTSen_{iu}, \min\left(AEI_{iu,}EOP_{iu}\right)\right\}, DASen_{hu}\right\rangle}^{DASen_{hu}} DABen_{hu} \\ \left[\left[DASen_{hu} - \min\left\langle \min\left\{RTSen_{iu}, \max\left(AEI_{iu,}EOP_{iu}\right)\right\}, DASen_{hu}\right\rangle\right] \times RTPen_{iu}\right) - \\ \int_{\min\left\langle \min\left\{RTSen_{iu}, \max\left(AEI_{iu,}EOP_{iu}\right)\right\}, DASen_{hu}\right\rangle}^{DASen_{hu}} DABen_{hu} \end{cases} \begin{matrix} \times s_i, \\ \\ \times s_i \end{matrix}$$

RTD Interval Energy Component of DAMAP When Eligible Generators' Real-Time Energy Schedules are Greater Than or Equal to Their DAM Energy Schedules

$$CDAMPen_{iu} = If \left\{ \min \left\{ \begin{array}{l} AND\left(RTSen_{iu} \geq DASen_{hu}, RTSen_{iu} \geq EOP_{iu}, EOP_{iu} \geq DASen_{hu}\right), \\ \min \left\langle \begin{array}{c} \left(\left[DASen_{hu} - \max\left\langle \min\{RTSen_{iu}, \max(AEI_{iu}, EOP_{iu})\}, DASen_{hu}\right\rangle\right] \times RTPen_{iu}\right) + \\ \int_{DASen_{iu}}^{\max\left\langle \min\{RTSen_{iu}, \max(AEI_{iu}, EOP_{iu})\}, DASen_{hu}\right\rangle} RTBen_{iu} \end{array} \right\rangle \times s_i, 0 \right\}, \\ \min \left\langle \begin{array}{c} \left(\left[DASen_{hu} - \max\left\langle \max\{RTSen_{iu}, \min(AEI_{iu}, EOP_{iu})\}, DASen_{hu}\right\rangle\right] \times RTPen_{iu}\right) + \\ \int_{DASen_{iu}}^{\max\left\langle \max\{RTSen_{iu}, \min(AEI_{iu}, EOP_{iu})\}, DASen_{hu}\right\rangle} RTBen_{iu} \end{array} \right\rangle \times s_i, 0 \right\} \end{array} \right\}_i$$

RTD Interval Regulation Service Component of DAMAP When Eligible Generators' Real-Time Regulation Schedules are Different than their DAM Regulation Schedules

$$CDAM\Pr eg_{iu} = If \left\{ \begin{array}{l} RTSreg_{iu} \prec DASreg_{hu}, \{(DASreg_{hu} - RTSreg_{iu}) \times (RT\Pr eg_{iu} - DABreg_{hu})\} \times s_i, \\ \{(DASreg_{hu} - RTSreg_{iu}) \times \max(RT\Pr eg_{iu} - RTBreg_{hu}, 0)\} \times s_i \end{array} \right\}$$

RTD Interval Operating Reserves Component of DAMAP When Eligible Generators' Real-Time Reserves Schedules for any Operating Reserves Products are Different than their DAM Reserves Schedules

$$CDAM\Pr es_{iup} = If \left\{ \begin{array}{l} RTSres_{iup} \prec DASres_{hup}, \{(DASres_{hup} - RTSres_{iup}) \times (RT\Pr es_{iup} - DABres_{hup})\} \times s_i, \\ (DASres_{hup} - RTSres_{iup}) \times RT\Pr es_{iup} \times s_i \end{array} \right\}$$

Hourly DAMAP for Demand Side Resources

$$DAMP_{hu} = \max \left\{ 0, \sum_{i \in h} CDAMP_{iu} \right\}$$

Where:

$$CDAMP_{iu} = \sum_p CDAM\Pr es_{iup} + CDAM\Pr eg_{iu}$$

RTD Interval Regulation Service Component of DAMAP When Demand Side Resources' Real-Time Regulation Schedules are Different than their DAM Regulation Schedules

$$CDAM\Pr eg_{iu} = If \left\{ \begin{array}{l} RTSreg_{iu} \prec DASreg_{hu}, \{(DASreg_{hu} - RTSreg_{iu}) \times (RT\Pr eg_{iu} - DABreg_{hu})\} \times s_i, \\ \{(DASreg_{hu} - RTSreg_{iu}) \times \max(RT\Pr eg_{iu} - RTBreg_{hu}, 0)\} \times s_i \end{array} \right\}$$

RTD Interval Operating Reserves Component of DAMAP When Demand Side Resources' Real-Time Reserves Schedules for any Operating Reserves Products are Different than their DAM Reserves Schedules

$$CDAM\Pr es_{iup} = If \left\{ \begin{array}{l} RTSres_{iup} \prec DASres_{hup}, \left\{ \left(DASres_{hup} - RTSres_{iup} \right) \times \left(RT\Pr es_{iup} - DABres_{hup} \right) \right\} \times PI\operatorname{Re} s_{iu}^{RT} \times s_i, \\ \left(DASres_{hup} - RTSres_{iup} \right) \times RT\Pr es_{iup} \times PI\operatorname{Re} s_{iu}^{RT} \times s_i \end{array} \right\}$$

RTD Interval Regulation Service Component of DAMAP When Limited Energy Storage Resources' Real-Time Regulation Schedules are Different than their DAM Regulation Schedules

$$CDAM\Pr eg_{iu} = If \left\{ \begin{array}{l} RTSreg_{iu} \prec DASreg_{hu}, \left\{ \left(DASreg_{hu} - RTSreg_{iu} \right) \times \left(RT\Pr eg_{iu} - DABreg_{hu} \right) \right\} \times K_{PI} \times s_i, \\ \left\{ \left(DASreg_{hu} - RTSreg_{iu} \right) \times \max \left(RT\Pr eg_{iu} - RTBreg_{hu}, 0 \right) \right\} \times s_i \end{array} \right\}$$

Adjustments to Suppliers' DAM Energy, Regulation, and Operating Reserves Schedules Used for DAMAP Resulting from Supplier Requested Derates of Real-Time Operating Capacity

$$REDtot_{iu} = \max \left\{ 0, DASen_{hu} + DASreg_{hu} + \sum_p DASres_{hup} - RTUOL_{iu} \right\};$$

$$POTREDen_{iu} = \max \left\{ 0, DASen_{hu} - RTSen_{iu} \right\};$$

$$POTREDreg_{iu} = \max \left\{ 0, DASreg_{hu} - RTSreg_{iu} \right\};$$

$$POTREDres_{iup} = \max \left\{ 0, DASres_{hup} - RTSres_{iup} \right\};$$

$$REDen_{iu} = \left\{ REDtot_{iu} \times \left(POTREDen_{iu} \div \left[POTREDen_{hu} + POTREDreg_{hu} + \sum_p POTREDres_{hup} \right] \right) \right\};$$

$$REDreg_{iu} = \left\{ REDtot_{iu} \times \left(POTREDreg_{iu} \div \left[POTREDen_{hu} + POTREDreg_{hu} + \sum_p POTREDres_{hup} \right] \right) \right\};$$

$$REDres_{iup} = \left\{ REDtot_{iu} \times \left(POTREDres_{iup} \div \left[POTREDen_{hu} + POTREDreg_{hu} + \sum_p POTREDres_{hup} \right] \right) \right\};$$

Definitions of Variables Used in the Determination of DAMAP

s_i : Length of RTD interval *(i)*, expressed in hours;

h : Hour *(h)* which includes RTD interval *(i)*;

$DAMP_{hu}$:   DAMAP attributable in any hour *(h)* to any Supplier *(u)*, expressed in $;

$CDAMP_{iu}$:   Contribution of RTD interval *(i)* to the DAMAP to Supplier *(u)*, expressed in $;

$CDAMPen_{iu}$:   Energy component of RTD interval *(i)* to the DAMAP to Supplier *(u)*, expressed in $;

$CDAM\Pr eg_{iu}$:   Regulation Service component of RTD interval *(i)* to the DAMAP to Supplier *(u)*, expressed in $;

$CDAM\Pr es_{iu}$:   Operating Reserves Service component of RTD interval *(i)* to the DAMAP to Supplier *(u)*, determined separately for each Operating Reserves Service product, expressed in $;

$DASen_{hu}$:   DAM Energy schedule for Supplier *(u)* in hour *(h)*, expressed in megawatts, as may be adjusted by the variable $REDen_{iu}$, computed as described above, to reflect changes in the Generator's Emergency Upper Operating Limit or Normal Upper Operating Limit, whichever is applicable, in the event that the Supplier requests and is granted a derate of their real-time Operating Capacity;

$DASreg_{hu}$:   DAM Regulation Service schedule for Supplier *(u)* in hour *(h)*, expressed in megawatts, as may be adjusted by the variable $REDreg_{iu}$, computed as described above, to reflect changes in the Generator's Emergency Upper Operating Limit or Normal Upper Operating Limit, whichever is applicable, in the event that the Supplier requests and is granted a derate of their real-time Operating Capacity;

$DASres_{hup}$:   DAM Operating Reserves Service schedule for product *(p)* [i.e., 10-Minute Synchronous, 10-Minute Non-Synchronous, and 30-Minute Reserves] for Supplier *(u)* in hour *(h)*, expressed in megawatts, as may be adjusted by the variable $REDres_{iup}$, computed as described above, to reflect changes in the Generator's Emergency Upper Operating Limit or Normal Upper Operating Limit, whichever is applicable, in the event that the Supplier requests and is granted a derate of their real-time Operating Capacity;

$DABen_{hu}$:   DAM Energy bid curve by Supplier *(u)* in hour *(h)*, expressed in $/MW;

$DABreg_{hu}$:   DAM Availability bid for Regulation Service by Supplier *(u)* in hour *(h)*, expressed in MW;

$DABres_{hup}$:   DAM Availability bid for Operating Reserves Service bid for product *(p)* [i.e., 10-Minute Synchronous, 10-Minute Non-Synchronous, and 30-Minute Reserves] by Supplier *(u)* in hour *(h)*, expressed in $/MW;

$RTSen_{iu}$:   the Real-Time Energy scheduled for Supplier *(u)* in RTD interval *(i)*, computed as the arithmetic average of the six-second AGC Base Point Signals sent to Supplier *(u)* during the course of RTD interval *(i)*, expressed in MW;

$RTSreg_{iu}$:   the Real-Time Regulation Service scheduled for Supplier *(u)* in RTD interval *(i)*, expressed in MW;

$RTSres_{iup}$:   the Real-Time Operating Reserve Service scheduled for product *(p)* for Supplier *(u)* in RTD interval *(i)*, expressed in MW;

$RTBen_{iu}$:   the Real-Time Energy bid curve for Supplier *(u)* in RTD interval *(i)*, expressed in $/MW;

$RTBreg_{iu}$:   the Real-Time Availability bid for Regulation Service by Supplier *(u)* in RTD interval *(i)*, expressed in $/MW;

$RTBres_{iup}$:   the Real-Time Availability bid for Operating Reserve Service for product *(p)* by Supplier *(u)* in RTD interval *(i)*, expressed in $/MW;

AEI_{iu} :   the Average Actual Energy Injection by Supplier *(u)* in RTD interval *(i)*, but not more than $RTSen_{iup}$ plus Compensable Overgeneration, expressed in MW;

$RTPen_{iu}$:   the Real-Time LBMP [i.e., Energy plus Marginal Losses minus Marginal Congestion] at the location of Supplier *(u)* in RTD interval *(i)*, expressed in $/MWh;

$RT\Pr eg_{iu}$:   the Real-Time Market Clearing Price for Regulation Service at the location of Supplier *(u)* in RTD interval *(i)*, expressed in $/MW;

$RT\Pr es_{iup}$:   the Real-Time Market Clearing Price for Operating Reserve Service for product *(p)* at the location of Supplier *(u)* in RTD interval *(i)*, expressed in $/MW;

$PI\operatorname{Re}s_{iu}$:   the Reserve Performance Index in RTD interval *(i)* for Demand Side Resource *(u)*, expresses as a decimal value between zero and one, as determined in Appendix G;

K_{PI} :   the factor derived from the Regulation Service Performance index for Resource *(u)* for RTD interval *(i)*, which is initially be set at 1.0 for LESRs, as determined in Appendix G;

$RTUOL_{iu}$:   the Real-Time Emergency Upper Operating Limit or Normal Upper Operating Limit, whichever is applicable, of Supplier *(u)* in RTD interval *(i)*, expressed in MW;

$REDtot_{iu}$:   the total amount that DAM schedules need to be reduced to account for a derate of Operating Capacity for Supplier *(u)* in RTD interval *(i)*, expressed in MW;

$REDen_{iu}$:   the amount that the DAM Energy schedule ($DASen_{hu}$) needs to be reduced for the purposes of computing DAMAP to account for a derate of Operating Capacity for Supplier *(u)* in RTD interval *(i)*, expressed in MW;

$REDreg_{iu}$:   the amount that the DAM Regulation Service schedule ($DASreg_{hu}$) needs to be reduced for the purposes of computing DAMAP to account for a derate of Operating Capacity for Supplier *(u)* in RTD interval *(i)*, expressed in MW;

$REDres_{iup}$:   the amount that the DAM Operating Reserves Service schedule ($DASres_{hup}$) needs to be reduced for Operating Reserves product *(p)* [i.e., 10-Minute Synchronous, 10-Minute Non-Synchronous, and 30-Minute Reserves] for the purposes of computing DAMAP to account for a derate of Operating Capacity for Supplier *(u)* in RTD interval *(i)*, expressed in MW;

$POTREDen_{iu}$:   the potential amount that the DAM Energy schedule ($DASen_{hu}$) could be reduced for the purposes of computing DAMAP to account for a derate of Operating Capacity for Supplier *(u)* in RTD interval *(i)*, expressed in MW;

$POTREDreg_{iu}$:   the potential amount that the DAM Regulation Service schedule (

$DASreg_{hu}$) could be reduced for the purposes of computing DAMAP to account for a derate of Operating Capacity for Supplier *(u)* in RTD interval *(i)*, expressed in MW;

$POTREDres_{iup}$:   the potential amount that the DAM Operating Reserves Service schedule (

$DASres_{hup}$) could be reduced for Operating Reserves product *(p)* [i.e., 10-Minute Synchronous, 10-Minute Non-Synchronous, and 30-Minute Reserves] for the purposes of computing DAMAP to account for a derate of Operating Capacity for Supplier *(u)* in RTD interval *(i)*, expressed in MW; and

EOP_{iu}^{RT} :   Economic Operating Point for Generator *(u)* in RTD interval *(i)*, expressed in megawatts, determined as described in Appendix F.

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

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

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

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

>   *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 (Section 15.2) of the Market Administration and Control Area Services Tariff (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:

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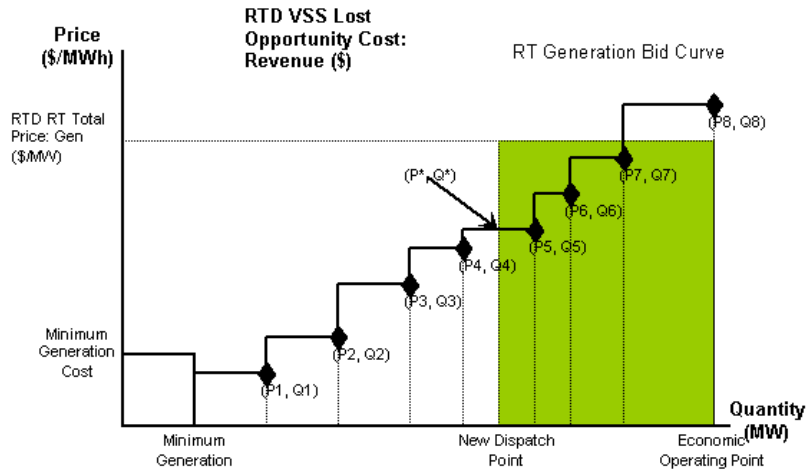
LOC_{Cost}^{RT} : Costs avoided by Generator *g* from being instructed to reduce its Energy output to provide Voltage Support Service, determined as illustrated below:

$$LOC_{Cost}^{RT} = \int_{\text{RTD New Dispatch Point (MW)}}^{\text{EOP (MW)}} \text{RTD Gen Bid}$$
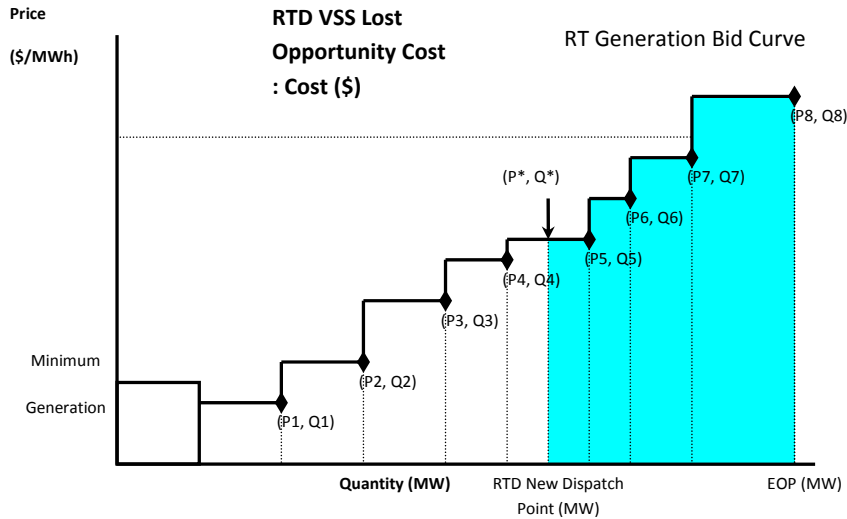
Regulation and Frequency Response Service Day-Ahead Market Settlement

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

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

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

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

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

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

BID_{gi}^{RT} :   Whenever $AGC_{gi}^{RT} > RTD_{gi}^{RT}$ and the Generator's actual Bid exceeds $\left[LBMPe_{gi}^{RT} + LBMPl_{gi}^{RT} - LBMPc_{gi}^{RT} \right]$, BID_{gi}^{RT} shall be set at a level equal to the lesser of the Generator's actual Bid or its reference Bid plus \$100/MWh. Whenever $AGC_{gi}^{RT} < RTD_{gi}^{RT}$ and the Generator's actual Bid is lower than $\left[LBMPe_{gi}^{RT} + LBMPl_{gi}^{RT} - LBMPc_{gi}^{RT} \right]$, BID_{gi}^{RT} 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

$$\sum_{1\to n}\left\{\begin{array}{l} If\_AND\left[\begin{array}{l} REGMW_{gi}^{RT}=0, OR\left(INSVC_{gi}^{RT}=Y, INSVC_{gi}^{RT}=R, EI_{gi}^{RT}>5\right), RTD_{gi}^{RT}>0, EI_{GI}^{RT}>0, \\ OOM_{gi}^{RT}\neq\langle 1,2,4,23,24,25,26,27,40,50\rangle, \\ OR\left(\begin{array}{l} Generator\_is\_not\_a\_PURPA\_unit, AND[No\_RT\_Bid\_Exists, No\_DAM\_Bid\_Exists], \\ AND\left[\begin{array}{l} RT\_Bid\_Exists, \\ OR\langle Unit\_Bid=ISO\_Committed\_Flexible, Unit\_Bid=Self\_Committed\_Flexible\rangle\end{array}\right], \\ AND\left[\begin{array}{l} DAM\_Bid\_Exists, No\_RT\_Bid\_Exists, \\ OROR\langle Unit\_Bid=ISO\_Committed\_Flexible, Unit\_Bid=Self\_Committed\_Flexible\rangle\end{array}\right]\end{array}\right) \\ OR\left(Unit\_Type\neq 30\_Minute\_GT, Unit\_Type\neq Quick\_Start\_GT, EI_{gi}^{RT}<0.7\times UOL_{gi}^{RT}\right)\end{array}\right], then \\ NCE_{gi}^{RT}\times REGMCP_{i}^{RT}\times s_{gi}^{RT}; \\ Otherwise\_\$0.\end{array}\right\}$$

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;

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

$$\sum_{1 \to n}^{N} \left\{ 10NONMW_{gh}^{DA} \times 10NONMCP_h^{DA} \right\}$$

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

$$\sum_{1 \to n}^{N} \left\{ \left(10NONMW_{gi}^{RT} - 10NONMW_{gi}^{DA} \right) \times 10NONMCP_i^{RT} \times s_i^{RT} \right\}$$

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

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

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

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

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 megawatt hour 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:

$$\sum_{h=1}^{N}\left\{\begin{array}{l}\left[\max\left\langle\min\left(DRR_{rh}^{RT}, DRH_{rh}^{DA}\times1\_hour\right),0\right\rangle-\left\langle DRH_{rh}^{DA}\times1\_hour\right\rangle\right]\times\\\max\left[\begin{array}{l}\left\{\sum_{i=1}^{N}\left\langle\left(LBMPe_{ri}^{RT}+LBMPl_{ri}^{RT}-LBMPc_{ri}^{RT}\right)\times s_i^{RT}\right\rangle\right\},\\\left\{LBMPe_{rh}^{DA}+LBMPl_{rh}^{DA}-LBMPc_{rh}^{DA}\right\}\end{array}\right]\end{array}\right\};$$

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 megawatt hours;

$LBMPe_{rh}^{DA}$:   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;

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 megawatts.

Day-Ahead Energy Settlements for LBMP Market Energy Exports

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

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 megawatts 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

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

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 megawatts 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 megawatts 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 (FIC) for LBMP Exports Failing the NYISO Check-out Process

If Transaction Check -out Failure under MP Control,

$$\text{FIC}_{ti} = \Sigma_{i=1}^{N}\left(\left(\left(\text{TH}_{ti}^{\text{RTC}} - \text{THC}_{ti}^{\text{RT}}\right) \times s_{ti}^{\text{RT}}\right) \times \max\left(\left(\text{LBMP}_{\text{porti}}^{\text{RTC}} - \text{LBMP}_{\text{porti}}^{\text{RT}}\right), 0\right)\right);$$

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;

$\text{TH}_{ti}^{\text{RTC}}$:   LBMP Energy Export Transaction megawatts scheduled by RTC15 for hourly transactions and Rolling RTC for intra-hourly transactions containing RTD interval (*i*) to be imported through Transaction (*t*), expressed in terms of MW;

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

$\text{LBMP}_{\text{podti}}^{\text{RTC}}$:   RTC LBMP at the Proxy Generator Bus (pod), scheduled as the Point of Delivery for LBMP Energy Import Transaction (*t*), in RTD interval (*i*), expressed in $/MW, for hourly transactions the applicable LBMP from the RTC15 evaluation and for intra-hourly transactions the LBMP from the Rolling RTC that scheduled the transaction ;

:

$\text{LBMP}_{\text{tpodi}}^{\text{RT}}$:   RTD LBMP at Proxy Generator Bus (*pod*), scheduled as the Point of Delivery for LBMP Energy Import Transaction (*t*), in RTD interval (*i*), expressed in $/MW;

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

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

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

$otherwise\_\$0.$

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 megawatts scheduled by RTC₁₅ containing RTD interval (*i*) to be exported through Transaction (*t*), expressed in terms of MW;

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

$LBMPe_{podti}^{RTC_{15}}$:   Energy component of the RTC₁₅ 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;

$LBMPl_{podti}^{RTC_{15}}$: Losses component of the RTC₁₅ 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;

$LBMPc_{podti}^{RTC_{15}}$:   Congestion component of the RTC₁₅ 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.

$LBMPe_{podti}^{RT}$: 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;

$LBMPl_{podti}^{RT}$: 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;

$LBMPc_{podti}^{RT}$: 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, NTAC, and Trading Hub Settlements

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

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

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

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

GTR_{gh}^{DA} : Grandfather Transmission Right megawatts 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:

$$
If \left(\left[\begin{array}{l} LBMPc\ _{porth}^{DA} - LBMPc\ _{podth}^{DA} = LBMPc\ _{porgh}^{DA} - LBMPc\ _{podgh}^{DA}\ , \\ OR\ \begin{array}{l} \\ AND \left\langle \begin{array}{l} LBMPc\ _{porth}^{DA} - LBMPc\ _{podth}^{DA} > LBMPc\ _{porgh}^{DA} - LBMPc\ _{podgh}^{DA}\ , \\ LBMPc\ _{porth}^{DA} - LBMPc\ _{podth}^{DA} > \$0\,/\,MWh\ , LBMPc\ _{porgh}^{DA} - LBMPc\ _{podgh}^{DA} > \$0\,/\,MWh \end{array} \right\rangle \end{array} \end{array} \right], \right.
$$

$$
\left[\left\langle LBMPc\ _{porth}^{DA} - LBMPc\ _{podth}^{DA} \right\rangle - \left\langle LBMPc\ _{porgh}^{DA} - LBMPc\ _{podgh}^{DA} \right\rangle \right] \times GTRR\ _{h}^{DA}\ , \qquad)
$$

$$
If \left| \begin{array}{l} AND \left\langle \begin{array}{l} LBMPc\ _{porth}^{DA} - LBMPc\ _{podth}^{DA} < LBMPc\ _{porgh}^{DA} - LBMPc\ _{podgh}^{DA}\ , \\ LBMPc\ _{porth}^{DA} - LBMPc\ _{podth}^{DA} > \$0\,/\,MWh\ , LBMPc\ _{porgh}^{DA} - LBMPc\ _{podgh}^{DA} > \$0\,/\,MWh \end{array} \right\rangle, \\ \max \left\langle \left[\left\langle LBMPc\ _{porth}^{DA} - LBMPc\ _{podth}^{DA} \right\rangle - \left\langle LBMPc\ _{porgh}^{DA} - LBMPc\ _{podgh}^{DA} \right\rangle \right] \times GTRR\ _{h}^{DA}, \$0 \right\rangle' \end{array} \right.
$$

$$
If \left| \begin{array}{l} AND \left\langle LBMPc\ _{porth}^{DA} - LBMPc\ _{podth}^{DA} > \$0\,/\,MWh\ , LBMPc\ _{porgh}^{DA} - LBMPc\ _{podgh}^{DA} < \$0\,/\,MWh \right\rangle, \\ \min \left\langle \begin{array}{l} \left[\left\langle LBMPc\ _{porth}^{DA} - LBMPc\ _{podth}^{DA} \right\rangle - \left\langle LBMPc\ _{porgh}^{DA} - LBMPc\ _{podgh}^{DA} \right\rangle \right] \times GTRR\ _{h}^{DA}\ , \\ , \left\langle LBMPc\ _{porth}^{DA} - LBMPc\ _{podth}^{DA} \right\rangle \times GTRR\ _{h}^{DA} \end{array} \right\rangle, \\ If \left(\begin{array}{l} AND \left\langle \begin{array}{l} LBMPc\ _{porth}^{DA} - LBMPc\ _{podth}^{DA} \neq LBMPc\ _{porgh}^{DA} - LBMPc\ _{podgh}^{DA}\ , \\ LBMPc\ _{porth}^{DA} - LBMPc\ _{podth}^{DA} < \$0\,/\,MWh\ , LBMPc\ _{porgh}^{DA} - LBMPc\ _{podgh}^{DA} \neq \$0\,/\,MWh \end{array} \right\rangle, \\ \max \left\langle \begin{array}{l} \left[\left\langle LBMPc\ _{porth}^{DA} - LBMPc\ _{podth}^{DA} \right\rangle - \left\langle LBMPc\ _{porgh}^{DA} - LBMPc\ _{podgh}^{DA} \right\rangle \right] \times GTRR\ _{h}^{DA}\ , \\ \left\langle LBMPc\ _{porth}^{DA} - LBMPc\ _{podth}^{DA} \right\rangle \times GTRR\ _{h}^{DA} \end{array} \right\rangle, \$0 \end{array} \right) \end{array} \right.
$$

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Day-Ahead Replacement Energy for Curtailed Import Bilateral Transactions

$$
\begin{bmatrix}
Supplier\_of\_Energy\_for\_Transaction\_signed\_MST, \\
\begin{cases}
\left[\langle THBid_h^{DA} - TH_h^{DA}\rangle \times LBMPe_{porth}^{DA}\right]+ \\
\left[\langle THBid_h^{DA} - TH_h^{DA}\rangle \times LBMPl_{porth}^{DA}\right]- \\
\left[\langle THBid_h^{DA} - TH_h^{DA}\rangle \times LBMPc_{porth}^{DA}\right]
\end{cases}, \\
If\left\{\sum_{i=1}^{N}\begin{bmatrix}\langle THBid_h^{DA} - TH_h^{DA}\rangle \times \$100/MWh, \\ \sum_{i=1}^{N}\left\{\max\begin{bmatrix}\left(\begin{matrix}\left[\langle THBid_h^{DA} - TH_h^{DA}\rangle \times LBMPe_{porth}^{DA}\right]+ \\ 1.5\times\left[\langle THBid_h^{DA} - TH_h^{DA}\rangle \times LBMPl_{porth}^{DA}\right]- \\ \left[\langle THBid_h^{DA} - TH_h^{DA}\rangle \times LBMPc_{porth}^{DA}\right]\end{matrix}\right)\end{bmatrix}\right\}\end{bmatrix}\right\}
\end{bmatrix}
$$

Where:

t Set of Import Transactions *(t)*;

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

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

$THBid_h^{DA}:$ Import Transaction megawatts 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

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

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 megawatts scheduled Day-Ahead for Transaction (*t)* in the hour containing RTD interval (*i),* expressed in terms of MW;

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

- For Import Transactions, TH_{ti}^{RT} is set equal to the Bid megawatts 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

$$
\left|
\begin{array}{l}
Supplier\_of\_Energy\_for\_Transaction\_Signed\_MST, \\[2ex]
If \left\{ \sum_{i=1}^{N} \left\{ \left(\begin{array}{l} \left[\left\langle THBid_{ti}^{RT} - TH_{ti}^{RT} \right\rangle \times LBMPe_{porti}^{RT} \right] + \\ \left[\left\langle THBid_{ti}^{RT} - TH_{ti}^{RT} \right\rangle \times LBMPl_{porti}^{RT} \right] - \\ \left[\left\langle THBid_{ti}^{RT} - TH_{ti}^{RT} \right\rangle \times LBMPc_{porti}^{RT} \right] \end{array} \right) \times s_i^{RT} \right\}, \right. \\[6ex]
\left. \sum_{i=1}^{N} \left\{ \max \left[\begin{array}{l} \left\langle THBid_{ti}^{RT} - TH_{ti}^{RT} \right\rangle \times \$100/MWh \times s_i^{RT}, \\ 1.5 \times \left[\begin{array}{l} \left[\left\langle THBid_{ti}^{RT} - TH_{ti}^{RT} \right\rangle \times LBMPe_{porti}^{RT} \right] + \\ \left[\left\langle THBid_{ti}^{RT} - TH_{ti}^{RT} \right\rangle \times LBMPl_{porti}^{RT} \right] - \\ \left[\left\langle THBid_{ti}^{RT} - TH_{ti}^{RT} \right\rangle \times LBMPc_{porti}^{RT} \right] \end{array} \right] \times s_i^{RT} \end{array} \right] \right\}
\end{array}
\right.
$$

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 megawatts bid in RTC to be imported through Transaction (t) in the RTD interval (i), expressed in terms of MW

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

$THBid_{ti}^{RT}$:   Import Transaction megawatts 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 (FIC) for TUC Import Transactions Failing the NYISO Check-out Process

If Transaction Check -out Failure under MP Control,

$$FIC_{ti} = \sum_{i=1}^{N} \left(\left(\left(TH_{ti}^{RTC} - THC_{ti}^{RT} \right) \times s_{ti}^{RT} \right) \times \max \left(\left(LBMP_{porti}^{RT} - LBMP_{porti}^{RTC} \right), 0 \right) \right);$$

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}:   Import Transaction megawatts scheduled by RTC15 for hourly transactions and Rolling RTC for intra-hourly transactions containing RTD interval (i) to be imported through Transaction (t), expressed in terms of MW;

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

$LBMP_{porti}^{RTC}$:   RTC 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, for hourly transactions the applicable LBMP from the RTC15 evaluation and for intra-hourly transactions the LBMP from the Rolling RTC that scheduled the transaction ;

:

$LBMP_{porti}^{RT}$:   RTD 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;

:

Financial Impact Charge (FIC) for TUC Export Transactions Failing the NYISO Check-out Process

If Transaction Check -out Failure under MP Control,

$$\text{FIC}_{ti} = \sum_{i=1}^{N} \left(\left(\left(\text{TH}_{ti}^{\text{RTC}} - \text{THC}_{ti}^{\text{RT}} \right) \times s_{ti}^{\text{RT}} \right) \times \max \left(\left(\text{LBMP}_{\text{porti}}^{\text{RTC}} - \text{LBMP}_{\text{porti}}^{\text{RT}} \right), 0 \right) \right);$$

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;

$\text{TH}_{ti}^{\text{RTC}}$:   Export Transaction megawatts scheduled by RTC15 for hourly transactions and Rolling RTC for intra-hourly transactions containing RTD interval (*i*) to be imported through Transaction (*t*), expressed in terms of MW;

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

$\text{LBMP}_{\text{podti}}^{\text{RTC}}$:   RTC LBMP at the Proxy Generator Bus (pod), scheduled as the Point of Delivery for LBMP Energy Import Transaction (*t*), in RTD interval (*i*), expressed in $/MW, for hourly transactions the applicable LBMP from the RTC15 evaluation and for intra-hourly transactions the LBMP from the Rolling RTC that scheduled the transaction ;

:

$\text{LBMP}_{\text{tpodi}}^{\text{RT}}$:   RTD LBMP at Proxy Generator Bus (*pod*), scheduled as the Point of Delivery for LBMP Energy Import Transaction (*t*), in RTD interval (*i*), expressed in $/MW;

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

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

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

$$otherwise\_\$0.$$

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 megawatts scheduled by RTC15 containing RTD interval (*i*) to be imported through Transaction (*t*), expressed in terms of MW;

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

$LBMPe_{porti}^{RTC_{15}}$: Energy component of the RTC15 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 RTC15 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 RTC15 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 Import Transactions Failing the NYISO Check-out Process

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

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

$otherwise \_ \$0.$

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 megawatts scheduled by RTC$_{15}$ containing RTD interval (i) to be imported through Transaction (t), expressed in terms of MW;

TH_{ti}^{RT}: Import Transaction megawatts 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

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

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

$$otherwise\_\$0.$$

> **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 megawatts scheduled by RTC$_{15}$ containing RTD interval (i) to be exported through Transaction (t), expressed in terms of MW;
>
> TH_{ti}^{RT} :   Export Transaction megawatts 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.

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

If Transaction Check -out Failure under MP Control,

$$\text{FIC}_{ti} = \sum_{i=1}^{N}\left(\left(\left(\text{TH}_{ti}^{\text{RTC}} - \text{THC}_{ti}^{\text{RT}}\right) \times s_{ti}^{\text{RT}}\right) \times \max\left(\left(\text{LBMP}_{porti}^{\text{RT}} - \text{LBMP}_{porti}^{\text{RTC}}\right), 0\right)\right)$$

$$\pm\sum_{i=1}^{N}\left(\left(\left(\text{TH}_{ti}^{\text{RTC}} - \text{THC}_{ti}^{\text{RT}}\right) \times s_{ti}^{\text{RT}}\right) \times \max\left(\left(\text{LBMP}_{porti}^{\text{RTC}} - \text{LBMP}_{porti}^{\text{RT}}\right), 0\right)\right);$$

Otherwise $0

Where:

t: t Set of Wheel-through Transactions (*t*);

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

s_i: Length of RTD interval (*i*), expressed in hours;

$\text{TH}_{ti}^{\text{RTC}}$:   Wheel-through Transaction megawatts scheduled by RTC15 for hourly transactions and Rolling RTC for intra-hourly transactions containing RTD interval (*i*) to be imported through Transaction (*t*), expressed in terms of MW;

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

$\text{LBMP}_{porti}^{\text{RTC}}$:   RTC 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, for hourly transactions the applicable LBMP from the RTC15 evaluation and for intra-hourly transactions the LBMP from the Rolling RTC that scheduled the transaction ;

:

$\text{LBMP}_{porti}^{\text{RT}}$:   RTD 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;

$\text{LBMP}_{podti}^{\text{RTC}}$:   RTC LBMP at the Proxy Generator Bus (pod), scheduled as the Point of Delivery for LBMP Energy Import Transaction (*t*), in RTD interval (*i*), expressed in $/MW, for hourly transactions the applicable LBMP from the RTC15 evaluation and for intra-hourly transactions the LBMP from the Rolling RTC that scheduled the transaction ;

:

$\text{LBMP}_{tpodi}^{\text{RT}}$:   RTD LBMP at Proxy Generator Bus (*pod*), scheduled as the Point of Delivery for LBMP Energy Import Transaction (*t*), in RTD interval (*i*), expressed in $/MW.

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

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

$otherwise\_\$0.$

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 megawatts scheduled by RTC₁₅ containing RTD interval (*i*) to be wheeled through via Transaction (*t*), expressed in terms of MW;

TH_{ti}^{RT}:   Wheel-Through Transaction megawatts 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 RTC₁₅ 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 RTC₁₅ 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 RTC₁₅ 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.

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$LBMPe_{porti}^{RTC_{15}}$: ~~Energy component of the RTC₁₅ 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;~~

$LBMPl_{porti}^{RTC_{15}}$: ~~Losses component of the RTC₁₅ 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;~~

$LBMPc_{porti}^{RTC_{15}}$: ~~Congestion component of the RTC₁₅ 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.~~

$LBMPe_{porti}^{RT}$: ~~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;~~

$LBMPl_{porti}^{RT}$: ~~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;~~

$LBMPc_{porti}^{RT}$: ~~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

$$\sum_{1 \to n}^{N} \left\{ \left[TH_{th}^{RT} \times NTAC\$_m \right] + \left[EB_{bh}^{RT} \times NTAC\$_m \right] \right\}$$

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

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

$NTAC\$_m$:   Monthly NTAC rate, expressed in $/MWh, as determined in Attachment H of the NYISO OATT;

Payment to NYPA of NTAC on LSE Withdrawals and Exports, LBMP Market Energy Exports, and Wheel-Through Transactions

$$\sum_{1 \to n}^{N} \left\{ \sum_{l \in L} LSENTAC_{hl} + \sum_{c \in C} EXPLNTAC_{hc} + \sum_{c \in C} EXPNTAC_{hc} + \sum_{c \in C} WTNTAC_{hc} \right\}$$

Where:

C : Set of Transmission Customers *(c)* engaged in Export, LBMP Energy Export, and Wheel-Through Transactions during month (m);

L : Set of LSE Buses *(l)* engaged in Energy transactions during month *(m)*;

N : Number of hours *(h)* in month *(m)*;

$LSENTAC_{hl}$: NTAC collected from LSE *(l)* in hour *(h)*, expressed in $;

$EXPLNTAC_{hc}$: NTAC collected from Transmission Customer *(c)* on LBMP Energy Export Transactions scheduled in hour *(h)*, exclusive of transactions with Points of Withdrawal in ISO-NE, expressed in $;

$EXPNTAC_{hc}$: NTAC collected from Transmission Customer *(c)* on Bilateral Export Transactions scheduled in hour *(h)*, exclusive of transactions with Points of Withdrawal in ISO-NE, expressed in $;

$WTNTAC_{hc}$: NTAC collected from Transmission Customer *(c)* on Wheel Through Transactions scheduled in hour *(h)*, exclusive of transactions with Points of Withdrawal in ISO-NE, expressed in $.

Day-Ahead Energy Settlements at Trading Hub Point of Injection (Source) Buses

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

Where:

THI : Trading Hub Point of Injection (Source) Bus;

N : Number of hours in the Dispatch Day

THE_{THIth}^{DA} : Energy scheduled Day-Ahead sourced from Trading Hub (*THI*) for Bilateral Transaction (*t*), purchased by the Trading Hub Energy Owner in hour (*h*) expressed in terms of MW;

$LBMPe_{zh}^{DA}$: Energy component of the Day-Ahead LBMP in the load zone (*z*) of Trading Hub (*THI*) in hour (*h*) expressed in terms of $/MWh;

$LBMPl_{zh}^{DA}$: Losses component of the Day-Ahead LBMP in the load zone (*z*) of Trading Hub (*THI*) in hour *(h)* expressed in terms of $/MWh; and

$LBMPc_{zh}^{DA}$: Congestion component of the Day-Ahead LBMP in the load zone (z) of Trading Hub (THI) in hour (h) expressed in terms of $/MWh.

Real-Time Market Energy Settlements at Trading Hub Point of Injection (Source) Buses

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

Where:

THI : Trading Hub Point of Injection (Source) Bus;

N : Number of hours in the Dispatch Day

THE_{THIth}^{DA} : Energy scheduled Day-Ahead sourced from Trading Hub (THI) for Bilateral Transaction (t), purchased by the Trading Hub Energy Owner in hour (h) expressed in terms of MW;

THE_{THIth}^{RT} : Energy scheduled in the Real-Time Market sourced from Trading Hub (THI) for Bilateral Transaction (t), purchased by the Trading Hub Energy Owner in hour (h) expressed in terms of megawatt hours;

$LBMPe_{zh}^{RT}$: Energy component of the hourly integrated Real-Time LBMP in the load zone (z) of Trading Hub (THI) in hour (h) expressed in terms of $/MWh;

$LBMPl_{zh}^{RT}$: Losses component of the hourly integrated Real-Time LBMP in the load zone (z) of Trading Hub (THI) in hour (h) expressed in terms of $/MWh;

$LBMPc_{zh}^{RT}$: Congestion component of the hourly integrated Real-Time LBMP in the load zone (z) of Trading Hub (THI) in hour (h) expressed in terms of $/MWh.

Day-Ahead Energy Settlements at Trading Hub Point of Withdrawal (Sink) Buses

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

Where:

THW : Trading Hub Point of Withdrawal (Sink) Bus;

N : Number of hours in the Dispatch Day

THE_{THWth}^{DA} : Energy scheduled Day-Ahead to be delivered to Trading Hub (*THW*) through Bilateral Transaction (*t*), sold by the Trading Hub Energy Owner in hour (*h)* expressed in terms of MW;

$LBMPe_{zh}^{DA}$: Energy component of the Day-Ahead LBMP in the load zone (*z*) of Trading Hub (*THW*) in hour (*h*) expressed in terms of $/MWh;

$LBMPl_{zh}^{DA}$: Losses component of the Day-Ahead LBMP in the load zone (*z*) of Trading Hub (*THW*) in hour (*h*) expressed in terms of $/MWh;

$LBMPc_{zh}^{DA}$: Congestion component of the Day-Ahead LBMP in the load zone (*z*) of Trading Hub (*THW*) in hour (*h*) expressed in terms of $/MWh.

Real-Time Market Energy Settlements at Trading Hub Point of Withdrawal (Sink) Buses

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

Where:

THW : Trading Hub Point of Withdrawal (Sink) Bus;

N : Number of hours in the Dispatch Day

THE_{THWth}^{DA} : Energy scheduled Day-Ahead to be delivered to Trading Hub (*THW*) through Bilateral Transaction (*t*), sold by the Trading Hub Energy Owner in hour (*h)* expressed in terms of MW;

THE_{THWth}^{RT} : Energy scheduled in the Real-Time Market to be delivered to Trading Hub (*THW*) through Bilateral Transaction (*t*), sold by the Trading Hub Energy Owner in hour (*h*) expressed in terms of megawatt hours;

$LBMPe_{zh}^{RT}$: Energy component of the hourly integrated Real-Time LBMP in the Load Zone (*z*) of Trading Hub (*THW*) in hour (*h*) expressed in terms of $/MWh;

$LBMPl_{zh}^{RT}$: Losses component of the hourly integrated Real-Time LBMP in the Load Zone (*z*) of Trading Hub (*THW*) in hour (*h*) expressed in terms of $/MWh;

$LBMPc_{zh}^{RT}$: Congestion component of the hourly integrated Real-Time LBMP in the Load Zone (*z*) of Trading Hub (*THW*) in hour (*h*) expressed in terms of $/MWh

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Appendix L.   Transmission Congestion Contract (TCC) and DAM Net Congestion Rent Settlements

Congestion Rent Payments and Charges to Primary Holders of TCCs

$$Congestion\_Payment = \sum_{1 \to h}^{N} \left(\sum_{1 \to x}^{X} \left\{ TCC_{hx} \times \left[LBMPCPOI_{hx}^{DA} - LBMPCPOW_{hx}^{DA} \right] \right\} \right).$$

Where:

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

X : Set of all Transmission Congestion Contracts *(x)*;

TCC_{hc} : Nominal value of TCC *(c)* in hour *(h)*, expressed in MW;

$LBMPCPOI_{hc}^{DA}$: Congestion Component of the DAM LBMP in hour *(h)* at the Point of Injection for TCC *(c)*, expressed in \$/MW;

$LBMPCPOW_{hc}^{DA}$: Congestion Component of the DAM LBMP in hour *(h)* at the Point of Withdrawal for TCC *(c)*, expressed in \$/MW;

Allocation of DAM Net Congestion Rent

$$\sum_{h=1}^{N} \left\{ \begin{bmatrix} \sum_{l \in L} LSELBMPR_{hl} + \sum_{c \in C} EXPLBMPR_{hc} + \sum_{c \in C} IMPLBMPR_{hc} + \\ \sum_{c \in C} EXPTUCR_{hc} + \sum_{c \in C} IMPTUCR_{hc} + \sum_{c \in C} WTTUCR_{hc} + \\ \sum_{g \in G} GENLBMPR_{hg} + \sum_{v \in V} VLLBMPR_{hz} + \sum_{v \in V} VSLBMPR_{hv} \end{bmatrix} - \\ \sum_{x \in X} TCCR_{hx} - \sum_{q \in T} O/R - t - S\&U/DCRSC\&CRSP_{hq} \end{matrix} \right\} \times$$

$$\left\{ \begin{matrix} \left(OR_{tm} + ETCNL_{tm} + NARs_{tm} + GFR\&GFTCC_{tm} \right) \div \\ \sum_{q \in T} \left(OR_{qm} + ETCNL_{qm} + NARs_{qm} + GFR\&GFTCC_{qm} \right) \end{matrix} \right\}$$

Where:

N : Number of hours *(h)* in month *(m)*;

L : Set of all LSEs *(l)*;

C : Set of all Transmission Customers *(c)*, excluding LSEs *(l)*;

G : Set of all Generators *(g)*;

V : Set of all Virtual Load (VL) and Virtual Supply (VS) bidders *(v)*;

X : Set of all TCCs *(x)*;

T : Set of all Transmission Owners (q);

t : Transmission Owner (t);

$LSELBMPR_{hl}$: DAM Congestion Rent paid or charged to LSE (l) in hour (h) for DAM Energy transactions, expressed in $;

$EXPLBMPR_{hc}$: DAM Congestion Rent paid or charged to Transmission Customer (c) in hour (h) for LBMP Energy Export Transactions scheduled in the DAM, expressed in $;

$IMPLBMPR_{hc}$: DAM Congestion Rent paid or charged to Transmission Customer (c) in hour (h) for LBMP Energy Import Transactions scheduled in the DAM, expressed in $;

$IMPTUCR_{hc}$: DAM Congestion Rent paid or charged to Transmission Customer (c) in hour (h) for Bilateral Import Transactions scheduled in the DAM, expressed in $;

$EXPTUCR_{hc}$: DAM Congestion Rent paid or charged to Transmission Customer (c) in hour (h) for Bilateral Export Transactions scheduled in the DAM, expressed in $;

$WTTUCR_{hc}$: DAM Congestion Rent paid or charged to Transmission Customer (c) in hour (h) for Wheel Through Transactions scheduled in the DAM, expressed in $;

$GENLBMPR_{hg}$: DAM Congestion Rent paid or charged to Generator (g) in hour (h) for DAM Energy Transactions scheduled in the DAM, expressed in $;

$VLLBMPR_{hv}$: DAM Congestion Rent paid or charged to Virtual Load bidder (v) in hour (h) for Virtual Load Transactions scheduled in the DAM, expressed in $;

$VSLBMPR_{hv}$: DAM Congestion Rent paid or charged to Virtual Supply bidder (v) in hour (h) for Virtual Supply Transactions scheduled in the DAM, expressed in $;

$TCCR_{hx}$: TCC Rent paid or charged to Primary Holder of TCC (x) in hour (h), expressed in $;

$O/R-t-S\&U/DCRSC\&CRSP_{hq}$: The sum of all Outage/Return-to-Service Congestion Rent Shortfall Charges, Uprate/Derate Congestion Rent Shortfall Charges, Outage/Return-to-Service Congestion Rent Surplus Payments, and Uprate/Derate Congestion Rent Surplus Payments for all Transmission Owners (q) in hour (h), expressed in $, derived as detailed in Section 20.2.4 of Attachment N of the OATT;

OR_{tm} : The one-month portion of the revenue for Transmission Owner (t) imputed to the Direct Sale or the sale in any Centralized TCC Auction sub-auction of Original Residual TCCs that are valid in month (m), expressed in $, as described in Section 20.2.5 of OATT Attachment N;

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$ETCNL_{tm}$: The sum of the one-month portion of the revenue Transmission Owner (*t*)

received as payment for the Direct Sale of ETCNL or for its ETCNL released in the Centralized TCC Auction sub-auction held for TCCs valid for month (*m*), expressed in $, , as described in Section 20.2.5 of OATT Attachment N;

$NARs_{tm}$: The one-month portion of the Net Auction Revenues Transmission Owner (*t*)

received in Centralized TCC Auction sub-auctions and Reconfiguration Auctions held for TCCs valid for month (*m*), exclusive of any revenue from the sale of Original Residual TCCs, expressed in $, , as described in Section 20.2.5 of OATT Attachment N;

$GFR \& GFTCC_{tm}$: The one-month portion of the imputed value of Grandfathered TCCs

and Grandfathered Rights, valued at their market clearing prices in the Reconfiguration Auction for month *(m)* (or one-sixth of the average market clearing price in stage 1 rounds in the 6-month sub-auction of the last Centralized TCC Auction if no Reconfiguration Auction was held for month m), provided that Transmission Owner *(t)* is the selling party and the Existing Transmission Agreement related to each Grandfathered TCC and Grandfathered Right remains valid in month *(m)*, expressed in $, as described in Section 20.2.5 of OATT Attachment N;

OR_{qm} : The one-month portion of the revenue for the set of Transmission Owners *(q)*

imputed to the Direct Sale or the sale in any Centralized TCC Auction sub-auction of Original Residual TCCs that are valid in month *(m)*, expressed in $, as described in Section 20.2.5 of OATT Attachment N;

$ETCNL_{qm}$: The sum of the one-month portion of the revenue the set of Transmission

Owners *(q)* received as payment for the Direct Sale of ETCNL or for its ETCNL released in the Centralized TCC Auction sub-auction held for TCCs valid for month *(m)*, expressed in $, as described in Section 20.2.5 of OATT Attachment N;

$NARs_{qm}$: The one-month portion of the Net Auction Revenues the set of Transmission

Owners *(q)* received in Centralized TCC Auction sub-auctions and Reconfiguration Auctions held for TCCs valid for month *(m)*, exclusive of any revenue from the sale of Original Residual TCCs, expressed in $, as described in Section 20.2.5 of OATT Attachment N;

$GFR \& GFTCC_{qm}$: The one-month portion of the imputed value of Grandfathered TCCs

and Grandfathered Rights, valued at their market clearing prices in the Reconfiguration Auction for month *(m)* (or one-sixth of the average market clearing price in stage 1 rounds in the 6-month sub-auction of the last Centralized TCC Auction if no Reconfiguration Auction was held for month *m*), provided that the set of Transmission Owners *(q)* are the selling parties and the Existing Transmission Agreement related to each Grandfathered TCC and Grandfathered Right remains valid in month *(m)*, expressed in $, as described in Section 20.2.5 of OATT Attachment N;

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Appendix M.   Ancillary Services Cost Recovery

OATT Schedule 1 Charge – NYISO Annual Budget Charge

Calculation of the NYISO Annual Budget Charge for Transmission Customers Participating in Physical Market Activity

The NYISO will charge, and each Transmission Customer that participates in physical market activity will pay, a NYISO annual budget charge, on a monthly basis as calculated according to the following formula:

$$
\begin{aligned}
\text{ISO Annual Budget Charge}_{c,M} \\
= \sum_{d=1}^{D} \sum_{h=1}^{N} \Big(\Big(\text{InjectionUnits}_{c,h} \\
\times (.2 \times \text{ISOCosts}_{annual} + \text{TotalEstWithdrawals}_{annual}) \Big) \\
+ \Big(\text{WithdrawalUnits}_{c,h} \\
\times (.8 \times \text{ISOCosts}_{annual} + \text{TotalEstWithdrawals}_{annual}) \Big) \Big)
\end{aligned}
$$

Where:

    c = Transmission Customer.

    M =The relevant month.

    D = Number of days (d) in the month.

    N = Number of hours (h) in the day.

ISOCostsAnnual = The sum, in $, of the NYISO's annual budgeted costs for the current calendar year.

InjectionUnits$_{c,h}$ = The Injection Billing Units, in negawatt hours, for Transmission Customer c in hour h.

WithdrawalUnits$_{c,h}$ = The Withdrawal Billing Units, in megawatt hours, for Transmission Customer c in hour h.

TotalEstWithdrawalUnitsAnnual = The sum, in megawatt hours, of estimated Withdrawal Billing Units for all Transmission Customers in the current calendar year as determined by the NYISO in the summer prior to the current calendar year.

The current 80%/20% cost allocation methodology between Withdrawal Billing Units and Injection Billing Units for the NYISO annual budget charge will remain unchanged through at least December 31, 2011, and will continue to remain unchanged until such time that a study is conducted and the results of the study warrant changing the 80%/20% cost allocation. The methodology for the review and modification of the NYISO annual budget charge and cost allocation is detailed in Section 6.1.2.3 of Schedule 1 of the *NYISO OATT*.

Calculation of the NYISO Annual Budget Charge for Transmission Customers Engaging in Virtual Transactions

The NYISO will charge, and each Transmission Customer that has its virtual bids accepted and thereby engages in Virtual Transactions will pay, a charge for such activity on a monthly basis as calculated according to the following formula:

$$\textbf{VTCharge}_{c,M} = \textbf{VTRate} \times \textbf{VTCleared}_{c,M}$$

Where:

c = Transmission Customer.

M = The relevant month.

VTCharge$_{c,M}$ = The amount, in $, for which Transmission Customer c is responsible for month M.

VTRate = For calendar year 2010, the applicable rate will be $0.065 per cleared megawatt hour of Virtual Transactions, based on a $2.0 million projected 2010 annual revenue requirement. For calendar years following 2010, the applicable rate will be calculated in accordance with the formula set forth in Section 6.1.2.4.4 of Schedule 1 of the *NYISO OATT*.

VTCleared$_{c,M}$ = The total cleared Virtual Transactions, in megawatt hours, for Transmission Customer c in month M.

The charge will appear in a manual adjustment applied to the initial month of the monthly invoice with the charge for Transmission Customers aggregated to the Billing Org level.

Calculation of the NYISO Annual Budget Charge for Transmission Customers Purchasing Transmission Congestion Contracts

The NYISO will charge, and each Transmission Customer that purchases Transmission Congestion Contracts — excluding Transmission Congestion Contracts that are created prior to

January 1, 2010 — will pay, a charge for such activity on a monthly basis as calculated according to the following formula:

$$\textbf{TCCCharge}_{c,M} = \textbf{TCCRate} \times \textbf{TCCSettled}_{c,M}$$

Where:

c = Transmission Customer.

M = The relevant month.

TCCharge$_{c,M}$ = The amount, in \$, for which Transmission Customer c is responsible for month M.

TCCRate = For calendar year 2010, the applicable rate will be \$0.02 per settled megawatt hour of Transmission Congestion Contracts, based on a \$6.7 million projected 2010 annual revenue requirement. For calendar years following 2010, the applicable rate will be calculated in accordance with the formula set forth in Section 6.1.2.4.4 of Schedule 1 of the *NYISO OATT*.

TCCSettled$_{c,M}$ = The total settled Transmission Congestion Contracts, excluding Transmission Congestion Contracts created prior to January 1, 2010, in megawatt hours, for Transmission Customer c in Month M.

The charge will appear in a manual adjustment applied to the initial month of the monthly invoice with the charge for Transmission Customers aggregated to the Billing Org level.

Calculation of the NYISO Annual Budget Charge for Transmission Customers Participating in the Special Case Resource Program or Emergency Demand Response Program

The NYISO will charge, and each Transmission Customer that participates in the NYISO's Special Case Resource program or its Emergency Demand Response program will pay, a charge for such activity on a monthly basis as calculated according to the following formula:

$$\textbf{SCR and EDR Charge}_{c,M}$$
$$= \textbf{DRInjections}_{c,M} \times (.\,\textbf{2} \times \textbf{ISOCosts}_{\textbf{Annual}} \div \textbf{TotalEstWithdrawalUnits}_{\textbf{Annual}})$$

Where:

c = Transmission Customer.

M = The relevant month.

SCR and EDR Charge$_{c,M}$ = The amount, in \$, for which Transmission Customer c is responsible for month M.

DRInjections$_{c,M}$ = The total Load reduction, in megawatt hours, measured and compensated during testing or an actual event for Transmission Customer c in month M.

ISOCosts$_{Annual}$ = The sum, in \$, of the NYISO's annual budgeted costs in the current calendar year.

TotalEstWithdrawalUnits$_{Annual}$ = The sum, in megawatt hours, of estimated Withdrawal Billing Units for all Transmission Customers in the current calendar year as determined by the NYISO in the summer prior to the current calendar year.

The charge will appear in a manual adjustment applied to the initial month of the monthly invoice with the charge for Transmission Customers aggregated to the Billing Org level.

Calculation of the Credit for Transmission Customers Participating in Physical Market Activity

The NYISO will distribute on a monthly basis the revenue collected from the NYISO annual budget charges to Transmission Customers for non-physical market activity, the Special Case Resource program and the Emergency Demand Response program, as calculated above, to each Transmission Customer participating in physical market activity, in accordance with the following formaula.

$$
\begin{aligned}
\textbf{ISO Annual Budget Credit}_{\textbf{c,M}} \\
= \Big(\textbf{NonPhysicalActivityRevenue}_{\textbf{M}} \\
\times \big(.\,\textbf{2} \times \textbf{InjectionUnits}_{\textbf{c,M}} \div \textbf{TotalInjectionUnits}_{\textbf{M}} \big) \Big) \\
+ \Big(\textbf{NonPhysicalActivityRevenue}_{\textbf{M}} \\
\times \big(.\,\textbf{8} \times \textbf{WithdrawalUnits}_{\textbf{c,M}} \\
\div \textbf{TotalWithdrawalUnits}_{\textbf{M}} \big) \Big)
\end{aligned}
$$

Where:

c = Transmission Customer.

M = The relevant month.

ISO Annual Budget Credit$_{c,M}$ = The amount, in \$, that Transmission Customer c will receive for month M.

NonPhysicalActivityRevenue$_{M}$ = The sum, in \$, of the revenue collected by the ISO for month M through the charges to Transmission Customers for non-physical market activity, the Special Cases Resource program, and the Emergency Demand Response program as calculated in Section 6.1.2.4 of Schedule 1 of the OATT.

InjectionUnits$_{c,M}$ = The Injection Billing Units, in megawatt hours, for Transmission Customer c in month M.

WithdrawalUnits$_{c,M}$ = The Withdrawal Billing Units, in megawatt hours, for Transmission Customer c in month M.

TotalInjectionUnits$_{M}$ = The sum, in megawatt hours, of Injection Billing Units for all Transmission Customers in month M.

TotalWithdrawalUnits$_{M}$ = The sum, in megawatt hours, of Withdrawal Billing Units for all Transmission Customers in month M.

The credit will appear in a manual adjustment applied to the monthly invoice with the charge for Transmission Customers aggregated to the Billing Org level.

OATT Schedule 1 Charge – NERC and NPCC Charges

The NYISO will charge, and each Transmission Customer will pay, a charge on a quarterly basis to recover the NERC and NPCC costs invoiced to the NYISO by NERC and NPCC for the upcoming calendar quarter as calculated according to the following formula:

$$\textbf{NERC\&NPCC Charge}_{c,Q} = \textbf{NERC\&NPCCCosts}_Q \times \textbf{TUWithdrawalUnits}_{c,M} \div \textbf{TUWithdrawalUnits}_M$$

Where:

c = Transmission Customer.

M = The relevant month.

Q = The relevant calendar quarter, for which the NERC and NPCC costs apply.

NERC&NPCC Charge$_{c,Q}$ = The amount of the NERC and NPCC costs invoiced to the NYISO, in $, for which Transmission Customer c is responsible for calendar quarter Q.

NERC&NPCCCosts$_Q$ = The NERC and NPCC costs, in $, invoiced to the NYISO for calendar quarter Q.

M = The month in which the NYISO charges Transmission Customers to recover NERC and NPCC costs for calendar quarter Q.

TUWithdrawalUnits$_{c,M}$ = The Withdrawal Billing Units, in megawatt hours, for Transmission Customer c in its four-month true-up invoice that is issued with its regular monthly invoice in month M, except for Withdrawal Billing Units for Wheels Through and Exports.

TUTotalWithdrawalUnits$_M$ = The sum, in megawatt hours, of Withdrawal Billing Units for all Transmission Customers in their four-month true-up invoices that are issued with their regular monthly invoices in month M, except for Withdrawal Billing Units for Wheels Through and Exports.

In calculating the Withdrawal Billing Units for this NERC and NPCC charge, the NYISO will use the LSE bus meter data that have been submitted by the meter authorities for use in the calculation of the four-month true-up of the Transmission Customer's monthly invoice pursuant to Sections 7.4.2.1.2 and 7.4.2.1.3 of the *NYISO Services Tariff* and Sections 2.7.4.3.1(ii) and 2.7.4.3.1(iii) of the *NYISO OATT*. This calculation of the NERC and NPCC charge shall not be subject to correction or adjustment.

The charge will appear in a manual adjustment with the charge for Transmission Customers aggregated to the Billing Org level.

OATT Schedule 1 Charge – Non-NYISO Facilities Payment Charge

Calculation of the Non-NYISO Facilities Payment Charge for Transmission Customers Based on Withdrawal Billing Units Not Used to Supply Station Power under Part 5 of the NYISO OATT

The NYISO will charge, and each Transmission Customer will pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, a non-NYISO facilities charge for each month, as calculated according to the following formula:

$$\text{Non} - \text{NYISO Facilities Payment Charge}_{c,M}$$

$$= \sum_{d=1}^{D} \left\{ \sum_{h=1}^{H} \left(\text{NonNYISOFacilitiesCosts}_M \div N \right. \right.$$

$$\left. \left. \times \text{WithdrawalUnits}_{c,h} \div \text{TotalWithdrawalUnits}_h \right) \right\}$$

Where:

c = Transmission Customer.

M = The relevant month.

D = Number of days (d) in the month.

H = Number of hours (h) in the day.

N = Total number of hours h in Month M.

Non-NYISO Facilities Payment Charge$_{c,M}$ = The amount, in $, for which Transmission Customer c is responsible for Month m.

NonNYISOFacilitiesCosts$_M$ = The sum, in $, of the NYISO's bills for month M for the non-NYISO facilities from (i) Consolidated Edison Co. of New York (less the one-half of such bill paid by PJM Interconnection, LLC) and (ii) Rochester Gas and Electric Corporation.

WithdrawalUnits$_{c,h}$ = The Withdrawal Billing Units, in megawatt hours, for Transmission Customer c in hour h, except for the Withdrawal Billing Units to supply Station Power as a third-party provider.

TotalWithdrawalUnits$_h$ = The sum, in megawatt hours, of Withdrawal Billing Units for all Transmission Customers in hour h, except for the Withdrawal Billing Units to supply Station Power as third-party providers.

Calculation of the Non-NYISO Facilities Payment Charge for Transmission Customers Based on Withdrawal Billing Units to Supply Station Power under Part 5 of the NYISO OATT

The NYISO will charge, and each Transmission Customer will pay based on its Withdrawal Billing Units used to supply Station Power as a third-party provider, a non-NYISO facilities charge for each month as calculated according to the following formula:

$$\text{Non} - \text{NYISO Facilities Payment Charge}_{c,M}$$

$$= \sum_{d=1}^{N} \left\{ \text{NonNYISOFacilitiesCosts}_M \div N \times \text{StationPower}_{c,d} \right.$$

$$\left. \div \text{TotalWithdrawalUnits}_d \right\}$$

Where:

c = Transmission Customer.

M = The relevant month.

d = A given day in month M.

N = Number of days d in month M.

StationPower$_{c,d}$ = The Withdrawal Billing Units, in megawatt hours, of Transmission Customer c used to supply Station Power as a third-party provider for day d.

Non-NYISO Facilities Payment Charge$_{c,M}$ = The amount, in $, for which Transmission Customer c is responsible for month M.

NonNYISOFacilitiesCosts$_M$ = The sum, in $, of the NYISO's bills for month M for the non-NYISO facilities from (i) Consolidated Edison Co. of New York (less the one-half of such bill paid by PJM Interconnection, LLC) and (ii) Rochester Gas and Electric Corporation.

TotalWithdrawalUnits$_d$ = The sum, in megawatt hours, of Withdrawal Billing Units for all Transmission Customers in day d, except for the Withdrawal Billing Units to supply Station Power as third-party providers.

Calculation of the Non-NYISO Facilities Payment Credit

The NYISO will credit each Transmission Customer based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, an amount of the revenue collected through the non-NYISO facilities payment charge recovered from third-party Station Power providers for each month. This credit will be calculated according to the following formula:

$$\text{Non} - \text{NYISO Facilities Payment Credit}_{c,M}$$
$$= \sum_{d=1}^{D} \{ \text{NonNYISOFacPayCharge}_d \times \text{WithdrawalUnits}_{c,d}$$
$$\div \text{TotalWithdrawalUnits}_d \}$$

Where:

c = Transmission Customer.

M = The relevant month

d = A given day in month M.

D = Number of days d in month M.

Non-NYISO Facilities Payment Credit$_{c,M}$ = The amount, in $, that Transmission Customer c will receive for month M.

NonNYISOFacPayCharge$_d$ = The sum of non-NYISO facilities payment charges, in $, for all Transmission Customers that supply Station Power as third-party providers for day d.

WithdrawalUnits$_{c,d}$ = The Withdrawal Billing Units, in megawatt hours, for Transmission Customer c in day d, except for the Withdrawal Billing Units to supply Station Power as a third-party provider.

TotalWithdrawalUnits$_d$ = The sum, in megawatt hours, of Withdrawal Billing Units for all Transmission Customers in day d, except for the Withdrawal Billing Units to supply Station Power as third-party providers.

OATT Schedule 1 Charge – Local Reliability Rules I-R3 and I-R5

The NYISO will charge, and each Transmission Customer will pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, a charge for the recovery of the costs of payments to Suppliers pursuant to the incremental cost recovery for units that responded to either (i) Local Reliability Rule I-R3 or (ii) Local Reliability Rule I-R5, as applicable, for each month. This charge shall be equal to the sum of the daily charges for the Transmission Customer, as calculated according to the following formula, for each day in the relevant month. TheNYISO will perform this calculation separately to recover as applicable either (i) the payment costs related to Local Reliability I-R3, or (ii) the payment costs related to Local Reliability Rule I-R5.

$$\text{Local Reliability Rules Payment Recovery Charge}_{c,M}$$
$$= \sum_{d=1}^{D}\{\text{LRR Payment}_d \times \text{TDWithdrawalUnits}_{c,d}$$
$$\div \text{TDTotalWithdrawalUnits}_d\}$$

Where:

M = The relevant month.

c = Transmission Customer.

d = A given day in the relevant month.

D= Number of days d in the relevant month.

Local Reliability Rules Payment Recovery Charge$_{c,M}$ = The amount, in $, for which Transmission Customer c is responsible for month M.

LRRPayment$_d$ - The amount, in $, paid in day d to Suppliers pursuant to the incremental cost recovery for units that responded, as applicable, to either (i) Local Reliability Rule I-R3 in the Consolidated Edison Transmission District or (ii) Local Reliability Rule I-R5 in the LIPA Transmission District.

TDWithdrawalUnits$_{c,d}$ = The Withdrawal Billing Units, in megawatt hours, for Transmission Customer c in day d in either (i) the Consolidated Edison Transmission District (in the case of Local Reliability Rule I-R3) or (ii) the LIPA Transmission District (in the case of Local Reliability Rule I-R5), except for the Withdrawal Billing Units to supply Station Power as a third-party provider.

TDTotalWithdrawalUnits$_d$ = The sum, in megawatt hours, of Withdrawal Billing Units for all Transmission Customers in day d in either (i) the Consolidated Edison Transmission District (in the case of Local Reliability Rule I-R3) or (ii) the LIPA Transmission District (in the case of Local Reliability Rule I-R5), except for the Withdrawal Billing Units to supply Station Power as third-party providers.

OATT Schedule 1 Charge – Residual Costs Paymen\Charge

Calculation of the Residual Costs Payment/Charge for Transmission Customers Based on Withdrawal Billing Units Not Used to Supply Station Power under Part 5 of the NYISO OATT

The NYISO will calculate, and each Transmission Customer will receive or pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, a residual costs payment or a residual costs charge for each month according to the formula below. If the result of the calculation below is positive, the NYISO will pay the Transmission Customer a residual costs payment for the relevant month. If the result of the calculation below is negative, the NYISO will charge the Transmission Customer a residual costs charge for the relevant month.

$$
\text{Residual Costs Payment/Charge}_{c,M}
$$
$$
= \sum_{d=1}^{D}\left\{\sum_{h=1}^{H}\left(\left(\text{CustomerPayments}_h\right.\right.\right.
$$
$$
-\ \text{ISOPayments}_h)\text{x WithdrawalUnits}_{c,h}
$$
$$
\left.\left.\div \text{TotalWithdrawalUnits}_h\right)\right\}
$$

Where:

M = The relevant month.

c = Transmission Customer.

h = A given hour in the relevant month.

H = the number of hours h in a day.

D = the number of days d in the relevant month.

Residual Costs Payment/Charge$_{c,M}$ = The amount, in \$, for month M that Transmission Customer c will receive (if positive) or for which Transmission Customer c is responsible (if negative).

WithdrawalUnits$_{c,h}$ = The Withdrawal Billing Units, in megawatt hours, for Transmission Customer c in hour h, except for the Withdrawal Billing Units to supply Station Power as a third-party provider.

TotalWithdrawalUnits$_h$ = The sum, in megawatt hours, of Withdrawal Billing Units for all Transmission Customers in hour h, except for the Withdrawal Billing Units to supply Station Power as third-party providers.

CustomerPayments$_h$ = The NYISO's receipts, in \$, for each hour h from Transmission Customers that equal the sum of the following components, which could be either positive or negative amounts:

   a. Payments of the Energy component and Marginal Losses component of LBMP for Energy scheduled in the LBMP Market in hour h in the Day-Ahead Market;
   b. Payments of the Energy component, Marginal Losses component, and Congestion component of LBMP for Energy purchased in the Real-Time LBMP Market for hour h that was not scheduled Day-Ahead;

   c. Payments of the Energy component, Marginal Losses component, and Congestion component of LBMP for Energy by Suppliers that provided less Energy in the real-time dispatch for hour h than they were scheduled Day-Ahead to provide in hour h for the LBMP Market;

   d. The Marginal Losses Component of the TUC payments made in accordance with the *NYISO OATT* for Bilateral Transactions that were scheduled in hour h in the Day-Ahead Market; and

   e. The Marginal Losses Component and Congestion Component of the real-time TUC payments made in accordance with the *NYISO OATT* for Bilateral Transactions that were not scheduled in hour h in the Day-Ahead Market.

ISOPayments$_h$ = The NYISO's payments, in $, in each hour h to Suppliers that equal the sum of the following components, which could be either positive or negative amounts;

   a. Payments of the Energy component and Marginal Losses component of LBMP for Energy to Suppliers that were scheduled to provide in the LBMP Market in hour h in the Day-Ahead Market;

   b. Payments to Suppliers of the Energy component, Marginal Losses component, and Congestion component of LBMP for Energy provided to the NYISO in the Real-Time Dispatch for hour h that those Suppliers were not scheduled to provide Energy in hour h in the Day-Ahead Market;

   c. Payments of the Energy component and Marginal Losses component of LBMP for Energy to LSEs that consumed less Energy in the real-time dispatch than those LSEs were scheduled Day-Ahead to consume in hour h; and

   d. Payments of the Marginal Losses component and Congestion component of the real-time TUC to Transmission Customers that reduced their Bilateral Transaction schedules for hour h after the Day-Ahead Market.

Calculation of the Residual Costs Payment/Charge for Transmission Customers Based on Withdrawal Billing Units to Supply Station Power under Part 5 of the NYISO OATT

The NYISO will calculate, and each Transmission Customer will receive or pay based on its Withdrawal Billing Units used to supply Station Power as a third-party provider, a residual costs payment or a residual costs charge for each month according to the formula below. If the result of the calculation below is positive, the NYISO will pay the Transmission Customer a residual costs payment for the relevant month. If the result of the calculation below is negative, the NYISO will charge the Transmission Customer a residual costs charge for the relevant month.

$$
\begin{aligned}
&\text{Residual Costs Payment/Charge}_{c,M} \\
&= \sum_{d=1}^{D}\left\{\sum_{h=1}^{H}\Big(\big(\text{CustomerPayments}_d \right. \\
&\quad - \ \text{ISOPayments}_d\big)\text{x Station Power}_{c,d} \\
&\quad \left. \div \text{TotalWithdrawalUnits}_d\Big)\right\}
\end{aligned}
$$

Where:

     c= Transmission Customer.

M = The relevant month.

d = A given day in month M.

D = Number of days d in month M.

StationPower$_{c,d}$ = The Withdrawal Billing Units, in megawatt hours, of Transmission Customer c used to supply Station Power as a third-party provider for day d.

Residual Costs Payment/Charge$_{c,M}$ = The amount, in \$, for month M that Transmission Customer c will receive (if positive) or for which Transmission Customer c is responsible (if negative).

CustomerPayments$_d$ = The NYISO's receipts, in \$, for each day d from Transmission Customers, which could be either positive or negative amounts, for the sum of the Transmission Customer payment components described above.

ISOPayments$_d$ = The NYISO's payments, in \$, for each day d to Suppliers, which could be either positive or negative amounts, for the sum of the NYISO payment components described above.

TotalWithdrawalUnits$_d$ = The sum, in megawatt hours, of Withdrawal Billing Units for all Transmission Customers in day d, except for the Withdrawal Billing Units to supply Station Power as third-party providers.

Calculation of the Residual Costs Adjustment

The NYISO will calculate, and each Transmission Customer will receive or pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, a residual costs adjustment for each month, according to the following formula. If the amount of the below calculation is positive for the month, the NYISO will pay the Transmission Customer the adjustment amount. If the amount of the below calculation is negative for the month, the NYISO will charge the Transmission Customer the adjustment amount.

$$\text{Residual Costs Adjustments}_{c,M}$$
$$= \sum_{d=1}^{N} \{\text{ResidCharge/PaymentCosts}_d \times \text{WithdrawalUnits}_{c,d}$$
$$\div \text{TotalWithdrawalUnits}_d\}$$

Where:

c = Transmission Customer.

M = The relevant month.

d = A given day in month M.

N = Number of days d in month M.

Residual Costs Adjustment$_{c,M}$ = The amount, in \$, for month M that Transmission Customer c will receive (if positive) or for which Transmission Customer c is responsible (if negative).

ResidCharge/PaymentCosts$_d$ = (i) If Transmission Customers were responsible for a residual costs charge for day d from third-party Station Power providers, the (positive) amount, in \$, of the costs that the NYISO has collected through the residual costs charges for all Transmission Customers for day d. (ii) If Transmission

Customers received a residual costs payment for day d from third-party Station Power providers, the (negative) amount, in $, of the revenue that the NYISO has paid through the residual costs payments to all Transmission Customers for day d.

WithdrawalUnits$_{c,d}$ = The Withdrawal Billing Units, in megawatt hours, for Transmission Customer c in day d, except for the Withdrawal Billing Units to supply Station Power as a third-party provider.

TotalWithdrawalUnits$_{d}$ = The sum, in megawatt hours, of Withdrawal Billing Units for all Transmission Customers in day d, except for the Withdrawal Billing Units to supply Station Power as third-party providers.

Storm Watch Redispatch Costs and Allocation

Calculation of Storm Watch Redispatch Cost

$$\sum_{1 \to N}^{M}\left\{\sum_{1 \to X}^{C}\left\{\max\left[\left\langle\begin{array}{l}\left(\left\{FLOW_{C,h}^{DAM}-FLOW_{C,i}^{RTD}\right\}-\max\left\{\left(FLOW_{C,h}^{DAM}-FLOW_{PC,i}^{RTD}\right),0\right\}\right)\times\\ \left(LBMPE_{C,i}^{RTD}+LBMPL_{C,i}^{RTD}-LBMPC_{C,i}^{RTD}\right)\times L\times 1\_hour\end{array}\right\rangle,0\right]\right\}\right\}$$

Where:

N : Number of hours (h) in month (M);

C : Set of constraints (C) affected by Storm Watch contingencies;

X : Number of constraints (C) comprising the set of constraints affected by Storm Watch contingencies;

L : Length of RTD interval (i), expressed in hours;

$Flow_{C,h}^{DAM}$: The scheduled DAM flow across constraint (C) in hour (h), which contains RTD interval (i), expressed in MW;

$Flow_{C,i}^{RTD}$: The real-time flow across constraint (C) in RTD interval (i), expressed in MW;

$Flow_{PC,i}^{RTD}$: The real-time pre-TSA contingency flow across constraint (C) in RTD interval (i), expressed in MW;

$LBMPE_{C,i}^{RTD}$: The Energy component of the real-time shadow price at Storm Watch constraint (C) in RTD interval (i), expressed in $/MW;

$LBMPL_{C,i}^{RTD}$: The Losses component of the real-time shadow price at Storm Watch constraint (C) in RTD interval (i), expressed in $/MW;

$LBMPC_{C,i}^{RTD}$: The Congestion component of the real-time shadow price at Storm Watch constraint (C) in RTD interval (i), expressed in $/MW;

Allocation of Storm Watch Redispatch Costs to Zone J Withdrawals

$$\sum_{1 \to N}^{M} \left\{ \sum_{1 \to X}^{C} \left\{ \max \left[\left\langle \begin{array}{c} \left(\left\{ FLOW_{C,h}^{DAM} - FLOW_{C,i}^{RTD} \right\} - \max \left\{ \left(FLOW_{C,h}^{DAM} - FLOW_{PC,i}^{RTD} \right), 0 \right\} \right) \times \\ \left(LBMPE_{C,i}^{RTD} + LBMPL_{C,i}^{RTD} - LBMPC_{C,i}^{RTD} \right) \times L \times 1\_hour \end{array} \right\rangle, 0 \right] \right\} \right\} \times$$

$$\left\{ \begin{array}{c} \left[WU_{L,M}^{LSE} + WU_{T,M}^{EXP} + WU_{T,M}^{LEXP} + WU_{T,M}^{WT} + WU_{L,M}^{SPLSE} \right] \div \\ \left[WU_{M}^{LSE} + WU_{M}^{EXP} + WU_{M}^{LEXP} + WU_{M}^{WT} + WU_{M}^{SPLSE} \right] \end{array} \right\}$$

Minus

$$\sum_{1 \to N}^{M} \left\{ \sum_{1 \to X}^{C} \left\{ \max \left[\left\langle \begin{array}{c} \left(\left\{ FLOW_{C,h}^{DAM} - FLOW_{C,i}^{RTD} \right\} - \max \left\{ \left(FLOW_{C,h}^{DAM} - FLOW_{PC,i}^{RTD} \right), 0 \right\} \right) \times \\ \left(LBMPE_{C,i}^{RTD} + LBMPL_{C,i}^{RTD} - LBMPC_{C,i}^{RTD} \right) \times L \times 1\_hour \end{array} \right\rangle, 0 \right] \right\} \right\} \times$$

$$\left\{ \left[WU_{L,M}^{LSE-J} + WU_{L,M}^{SPLSE-J} \right] \div \left[WU_{M}^{LSE-J} + WU_{M}^{SPLSE-J} \right] \right\}$$

Where:

N : Number of hours (h) in month (M);

C : Set of constraints (C) affected by Storm Watch contingencies;

X : Number of constraints (C) comprising the set of constraints affected by Storm Watch contingencies;

L : Length of RTD interval (i), expressed in hours;

$Flow_{C,h}^{DAM}$: The scheduled DAM flow across constraint (C) in hour (h), which contains RTD interval (i), expressed in MW;

$Flow_{C,i}^{RTD}$: The real-time flow across constraint (C) in RTD interval (i), expressed in MW;

$Flow_{PC,i}^{RTD}$: The real-time pre-TSA contingency flow across constraint (C) in RTD interval (i), expressed in MW;

$LBMPE_{C,i}^{RTD}$: The Energy component of the real-time shadow price at Storm Watch constraint (C) in RTD interval (i), expressed in $/MW;

$LBMPL_{C,i}^{RTD}$: The Losses component of the real-time shadow price at Storm Watch constraint (C) in RTD interval (i), expressed in $/MW;

$LBMPC_{C,i}^{RTD}$: The Congestion component of the real-time shadow price at Storm Watch constraint (C) in RTD interval (i), expressed in $/MW;

WU_{M}^{LSE} : Total Actual LSE Energy Withdrawals NYCA-wide in month (M), expressed in terms of megawatt hours;

WU_{M}^{EXP} : Total Actual Export Energy scheduled NYCA-wide in month (M), expressed in terms of megawatt hours;

WU_M^{LEXP} : Total Actual LBMP Export Energy scheduled NYCA-wide in month (M); expressed in terms of megawatt hours;

WU_M^{WT} : Total Actual Wheel-Through Energy scheduled NYCA-wide in month (M); expressed in terms of megawatt hours;

WU_M^{SPLSE} : Total Actual LSE Energy Withdrawals NYCA-wide for LSE taking service under Section 5 of the OATT to supply Station Power in month (M), expressed in terms of megawatt hours;

$WU_{L,M}^{LSE}$: Actual LSE Energy Withdrawal in month (M) for LSE (L), expressed in terms of megawatt hours;

$WU_{T,M}^{EXP}$: Total Actual Export Energy scheduled in month (M) for Transmission Customer (T), expressed in terms of megawatt hours;

$WU_{T,M}^{LEXP}$: Total Actual LBMP Export Energy scheduled in month (M) for Transmission Customer (T), expressed in terms of megawatt hours;

$WU_{T,M}^{WT}$: Total Actual Wheel-Through Energy scheduled in month (M) for Transmission Customer (T), expressed in terms of megawatt hours;

$WU_{L,M}^{SPLSE}$: Total Actual LSE Energy Withdrawal for LSE (L) taking service under Section 5 of the OATT to supply Station Power in month (M), expressed in terms of megawatt hours;

$WU_{L,M}^{LSE-J}$: Actual LSE Energy Withdrawal in month (M) for Zone J LSE (L), expressed in terms of megawatt hours;

WU_M^{LSE-J} : Total Actual LSE Energy Withdrawals in month (M) for LSEs in Zone J, expressed in terms of megawatt hours;

$WU_{L,M}^{SPLSE-J}$: Actual LSE Energy Withdrawal for Zone J LSE (L) taking service under Section 5 of the OATT to supply Station Power in month (M), expressed in terms of megawatt hours;

$WU_M^{SPLSE-J}$: Total Actual LSE Energy Withdrawals by Zone J LSEs taking service under Section 5 of the OATT to supply Station Power in month (M), expressed in terms of megawatt hours;

OATT Schedule 1 Charge – Special Case Resources and Curtailment Service Providers

Calculation of a Charge for the Recovery of Costs for Payments for Special Case Resources and Curtailment Service Providers Called to Meet the Reliability Needs of a Local System

The NYISO will recover the costs of payments to Special Case Resources (SCRs) and Curtailment Service Providers (CSPs) that were called to meet the reliability needs of a local system. To do so, the NYISO will charge, and each Transmission Customer that serves Load in the Subzone for which the reliability services of the SCRs and CSPs were called will pay based

on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, a charge in accordance with the following formula for each Subzone:

$$\text{Local Reliability SCR and CSP Charge}_{c,M}$$

$$= \sum_{d=1}^{D} \left\{ \sum_{h=1}^{H} \left(\text{LocalReliability Costs}_h \times \text{SZWithdrawalUnits}_{c,h} \right. \right.$$

$$\left. \left. \div \text{SZTotalWithdrawalUnits}_h \right) \right\}$$

Where:

M = The relevant month.

c = Transmission Customer.

H = The number of hours h in a day.

D = The number of days d in month M.

Local Reliability SCR and CSP Charge$_{c,M}$ = The amount, in \$, for which Transmission Customer c is responsible for month M for the relevant Subzone.

LocalReliabilityCosts$_h$ = The payments, in \$, for hour h in the relevant Subzone made to Suppliers for SCRs and CSPs called to meet the reliability needs of that Subzone.

SZWithdrawalUnits$_{c,h}$ = The Withdrawal Billing Units, in megawatt hours, for Transmission Customer c in hour h in the relevant Subzone, except for Withdrawal Billing Units for Wheels Through, Exports, and to supply Station Power as a third-party provider.

SZTotalWithdrawalUnits$_h$ = The sum, in megawatt hours, of Withdrawal Billing Units for all Transmission Customers in hour h in the relevant Subzone, except for Withdrawal Billing Units for Wheels Through, Exports, and to supply Station Power as third-party providers.

Calculation of a Charge for the Recovery of Costs for Payments for Special Case Resources and Curtailment Service Providers Called to Meet the Reliability Needs of the NYCA

The NYISO will recover the costs of payments to SCRs and CSPs that were called to meet the reliability needs of the NYCA. To do so, the NYISO will charge, and each Transmission Customer that serves Load in the New York Control Area (NYCA) will pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, a charge in accordance with the following formula:

$$\text{NYCA Reliability SCR and CSP Charge}_{c,M}$$

$$= \sum_{d=1}^{D} \left\{ \sum_{h=1}^{H} \left(\text{NYCAReliability Costs}_h \times \text{WithdrawalUnits}_{c,h} \right. \right.$$

$$\left. \left. \div \text{TotalWithdrawalUnits}_h \right) \right\}$$

Where:

M = The relevant month.

c = Transmission Customer.

H = The number of hours h in a day.

D = The number of days d in month M.

NYCA Reliability SCR and CSP Charge$_{c,M}$ = The amount, in $, for which Transmission Customer c is responsible for month M.

NYCAReliabilityCosts$_h$ = The payments, in $, for hour h made to Suppliers for SCRs and CSPs called to meet the reliability needs of the NYCA.

WithdrawalUnits$_{c,h}$ = The Withdrawal Billing Units, in megawatt hours, for Transmission Customer c in hour h, except for Withdrawal Billing Units to supply Station Power as a third-party provider.

TotalWithdrawalUnits$_h$ = The sum, in megawatt hours, of Withdrawal Billing Units for all Transmission Customers in hour h, except for Withdrawal Billing Units to supply Station Power as third-party providers.

OATT Rate Schedule 1 Charge – Local Reliability Day-Ahead Margin Assurance Payments Charge

Calculation of the Local Reliability Day-Ahead Margin Assurance Payment (DAMAP) Charge for Transmission Customers Based on Withdrawal Billing Units Not Used to Supply Station Power under Part 5 of the NYISO OATT

The NYISO will charge, and each Transmission Customer that serves Load in the Subzone where the Resource is located will pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, a charge in accordance with the following formula for each Subzone:

$$
\text{Local Reliability DAMAP Charge}_{c,M}
$$
$$
= \sum_{d=1}^{D} \left\{ \sum_{h=1}^{H} \left(\text{DAMAPCosts}_h \times \text{SZWithdrawalUnits}_{c,h} \right. \right.
$$
$$
\left. \left. \div \text{SZTotalWithdrawalUnits}_h \right) \right\}
$$

Where:

c = Transmission Customer,

D = Number of days (d) in the month,

H = Number of hours (h) in the day,

M = The relevant month,

Local Reliability DAMAP Charge$_{c,M}$ = The amount, in $, for which Transmission Customer c is responsible for month M for the relevant Subzone.

DAMAPCosts$_h$ = The DAMAP costs, in $, for hour h in the relevant Subzone incurred to compensate Resources meeting the reliability needs of that Subzone.

SZWithdrawalUnits$_{c,h}$ = The Withdrawal Billing Units, in megawatt hours, for Transmission Customer c in hour h in the relevant Subzone, except for Withdrawal Billing Units for Wheels Through, Exports, and to supply Station Power as a third-party provider.

SZTotalWithdrawalUnits$_h$ = The sum, in megawatt hours, of Withdrawal Billing Units for all Transmission Customers in hour h in the relevant Subzone, except for Withdrawal Billing Units for Wheels Through, Exports, and to supply Station Power as third-party providers.

Calculation of the Local Reliability DAMAP Charge for Transmission Customers Based on Withdrawal Billing Units to Supply Station Power under Part 5 of the NYISO OATT

The NYISO will charge, and each Transmission Customer that serves Load in the Subzone where the Resource is located will pay based on its Withdrawal Billing Units used to supply Station Power as a third-party provider, a charge in accordance with the following formula for each Subzone:

$$\text{Local Reliability DAMAP Charge}_{c,M}$$
$$= \sum_{d=1}^{N} \{ \text{DAMAPCosts}_d \times \text{SZStationPower}_{c,d}$$
$$\div \text{SZTotalWithdrawalUnits}_d \}$$

> ***Where:***
>
> *c* = Transmission Customer.
>
> *M* = The relevant month.
>
> *d* = A given day in month M.
>
> *N* = Number of days d in month M.
>
> *Local Reliability DAMAP Charge*$_{c,M}$ = The amount, in $, that Transmission Customer c is responsible for month m for the relevant Subzone.
>
> *SZStationPower*$_{c,d}$ = The Withdrawal Billing Units, in megawatt hours, of Transmission Customer c in day d in the relevant Subzone that are used to supply Station Power as a third-party provider, except for Withdrawal Billing Units for Wheels Through and Exports.
>
> *DAMAPCosts*$_d$ = The DAMAP costs, in $, for day d in the relevant Subzone incurred to compensate Resources meeting the reliability needs of that Subzone.
>
> *SZTotalWithdrawalUnits*$_d$ = The sum, in megawatt hours, of Withdrawal Billing Units for all Transmission Customers in day d in the relevant Subzone, except for Withdrawal Billing Units for Wheels Through, Exports, and to supply Station Power as third-party providers.

Calculation of the Local Reliability DAMAP Credit

The NYISO will calculate, and each Transmission Customer that serves Load in the Subzone where the Resource is located will receive based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, an amount of the revenue collected

through the Local Reliability DAMAP charge recovered from third-party Station Power providers. This credit shall be calculated according to the following formula:

$$\text{Local Reliability DAMAP Credit}_{c,M}$$

$$= \sum_{d=1}^{N} \{ \text{LocRelDAMAPCharge}_d \times \text{SZWithdrawalUnits}_{c,d}$$

$$\div \text{SZTotalWithdrawalUnits}_d \}$$

Where:

M = The relevant month.

d = A given day in month M.

N = Number of days d in month M.

Local Reliability DAMAP Credit$_{c,M}$ = The amount, in $, that Transmission Customer c will receive for month M for the relevant Subzone.

LocRelDAMAPCharge$_d$ = The sum of Local Reliability DAMAP charges, in $, for all Transmission Customers supplying Station Power as third-party providers in the relevant Subzone as calculated above for day d.

SZWithdrawalUnits$_{c,d}$ = The Withdrawal Billing Units, in megawatt hours, for Transmission Customer c in day d in the relevant Subzone, except for Withdrawal Billing Units for Wheels Through, Exports, and to supply Station Power as a third-party provider.

SZTotalWithdrawalUnits$_d$ = The sum, in megawatt hours, of Withdrawal Billing Units for all Transmission Customers in day d in the relevant Subzone, except for Withdrawal Billing Units for Wheels Through, Exports, and to supply Station Power as third-party providers.

OATT Rate Schedule 1 Charge – NYCA Reliability DAMAP Charge

Calculation of the NYCA Reliability DAMAP Charge for Transmission Customers Based on Withdrawal Billing Units Not Used to Supply Station Power under Part 5 of the NYISO OATT

The NYISO will charge, and each Transmission Customer will pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, a charge in accordance with the following formula:

$$\text{NYCA DAMAP Charge}_{c,M}$$

$$= \sum_{d=1}^{D} \left\{ \sum_{h=1}^{H} \left(\text{NYCADAMAPCosts}_h \times \text{WithdrawalUnits}_{c,h} \right. \right.$$

$$\left. \left. \div \text{TotalWithdrawalUnits}_h \right) \right\}$$

Where:

c = Transmission Customer,

D = Number of days (d) in month M,

H = Number of hours (h) in the day,

M= The relevant month,

NYCA DAMAP Charge$_{c,M}$ = The amount, in $, for which Transmission Customer c is responsible for Month m.

NYCADAMAPCosts$_h$ = The DAMAP costs, in $, for hour h incurred to compensate Resources meeting the reliability needs of the NYCA.

WithdrawalUnits$_{c,h}$ = The Withdrawal Billing Units, in megawatt hours, for Transmission Customer c in hour h, except for Withdrawal Billing Units to supply Station Power as a third-party provider.

TotalWithdrawalUnits$_h$ = The sum, in megawatt hours, of Withdrawal Billing Units for all Transmission Customers in hour h, except for Withdrawal Billing Units to supply Station Power as third-party providers.

Calculation of the NYCA Reliability DAMAP Charge for Transmission Customers Based on Withdrawal Billing Units to Supply Station Power under Part 5 of the NYISO OATT

The NYISO will charge, and each Transmission Customer will pay based on its Withdrawal Billing Units used to supply Station Power as a third-party provider, a charge in accordance with the following formula:

$$NYCAReliability\,DAMAP\,Charge_{c,M}$$
$$= \sum_{d=1}^{N} \{NYCADAMAPCosts_d \div TotalWithdrawalUnits_d$$
$$\times StationPower_{c,d}\}$$

Where:

c = Transmission Customer.

M = The relevant month.

d = A given day in month M.

N = Number of days d in month M.

NYCA Reliability DAMAP Charge$_{c,m}$ = The amount, in $, for which Transmission Customer c is responsible for Month M.

StationPower$_{c,d}$ = The Withdrawal Billing Units, in megawatt hours, of Transmission Customer c in day d that are used to supply Station Power as a third-party provider.

NYCADAMAPCosts$_d$ = The DAMAP costs, in $, for day d incurred to compensate Resources meeting the reliability needs of the NYCA.

TotalWithdrawalUnits$_d$ = The sum, in megawatt hours, of Withdrawal Billing Units for all Transmission Customers in day d, except for Withdrawal Billing Units to supply Station Power as third-party providers.

Calculation of the NYCA Reliability DAMAP Credit

The NYISO will calculate, and each Transmission Customer will receive based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, an

amount of the revenue collected through the NYCA Reliability DAMAP charge recovered from third-party Station Power providers. This credit shall be calculated according to the following formula:

$$\text{NYCA Reliability DAMAP Credit}_{c,M}$$

$$= \sum_{d=1}^{N} \{ \text{NYCADAMAPCharge}_d \times \text{WithdrawalUnits}_{c,d}$$

$$\div \text{TotalWithdrawalUnits}_d \}$$

Where:

c = Transmission Customer.

M = The relevant month.

d = A given day in month M.

N = Number of days d in month M.

NYCA Reliability DAMAP Credit$_{c,M}$ = The amount, in \$, that Transmission Customer c will receive for month M.

NYCADAMAPCharge$_d$ = The sum of NYCA Reliability DAMAP charges, in \$, for all Transmission Customers supplying station power as third-party providers as calculated above for day d.

WithdrawalUnits$_{c,d}$ = The Withdrawal Billing Units, in megawatt hours, for Transmission Customer c in day d, except for Withdrawal Billing Units to supply Station Power as a third-party provider.

TotalWithdrawalUnits$_d$ = The sum, in megawatt hours, of Withdrawal Billing Units for all Transmission Customers in day d, except for the Withdrawal Billing Units to supply Station Power as third-party providers.

OATT Schedule 1 Charge – Import Curtailment Guarantee Payment Charge

Calculation of the Import Curtailment Guarantee Payment Charge for Transmission Customers Based on Withdrawal Billing Units Not Used to Supply Station Power under Part 5 of the NYISO OATT

The NYISO will charge, and each Transmission Customer will pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, a monthly charge to recover the costs of all Import Curtailment Guarantee Payments paid to Import Suppliers for each month. This monthly charge will be calculated in accordance with the following formula:

$$\text{Import Curtailment Guarantee Charge}_{c,M}$$

$$= \sum_{d=1}^{D} \left\{ \sum_{h=1}^{H} \left(\text{ImportCurtGuarCosts}_h \times \text{WithdrawalUnits}_{c,h} \right. \right.$$

$$\left. \left. \div \text{TotalWithdrawalUnits}_h \right) \right\}$$

Where:

c = Transmission Customer,

D = Number of days (d) in the month,

H = Number of hours (h) in the day,

M = The relevant month,

Import Curtailment Guarantee Charge$_{c,M}$ = The amount, in \$, for which Transmission Customer c is responsible for month M.

ImportCurtGuarCosts$_h$ = The costs, in \$, for the Import Guarantee payments to Import Suppliers for hour h.

WithdrawalUnits$_{c,h}$ = The Withdrawal Billing Units, in megawatt hours, for Transmission Customer c in hour h, except for Withdrawal Billing Units to supply Station Power as a third-party provider.

TotalWithdrawalUnits$_h$ = The sum, in megawatt hours, of Withdrawal Billing Units for all Transmission Customers in hour h, except for Withdrawal Billing Units to supply Station Power as third-party providers.

Calculation of the Import Supplier Guarantee Payment Charge for Transmission Customers Based on Withdrawal Billing Units to Supply Station Power under Part 5 of the NYISO OATT

The NYISO will charge, and each Transmission Customer will pay based on its Withdrawal Billing Units used to supply Station Power as a third-party provider, a monthly charge to recover the costs of all Import Supplier Guarantee Payments paid to Import Suppliers for each month. This charge will be calculated in accordance with the following formula:

$$\text{Import Curtailment Guarantee Charge}_{c,M}$$
$$= \sum_{d=1}^{D} \{\text{ImportCurtGuarCosts}_d \times \text{StationPower}_{c,d}$$
$$\div \text{TotalWithdrawalUnits}_d\}$$

Where:

c = Transmission Customer.

M = The relevant month.

d = A given day in month M.

D = Number of days d in month M.

Import Curtailment Guarantee Charge$_{c,M}$ = The amount, in \$, for which Transmission Customer c is responsible for month M.

StationPower$_{c,d}$ = The Withdrawal Billing Units, in megawatt hours, of Transmission Customer c in day d that are used to supply Station Power as a third-party provider.

ImportCurtGuarCosts$_d$ = The costs, in \$, for the Import Guarantee payments to Import Suppliers for day d.

$TotalWithdrawalUnits_d$ = The sum, in megawatt hours, of Withdrawal Billing Units for all Transmission Customers in day d, except for Withdrawal Billing Units to supply Station Power as third-party providers.

Calculation of the Import Curtailment Guarantee Credit

The NYISO will credit each Transmission Customer based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, an amount of the revenue collected through the Import Curtailment Guarantee charge recovered from third-party Station Power suppliers for each month. This credit will be calculated according to the following formula.

Import Curtailment Guarantee Credit$_{c,M}$
$$= \sum_{d=1}^{D} \{ \textbf{ImportCurtGuarCharge}_d \times \textbf{WithdrawalUnits}_{c,d} \div \textbf{TotalWithdrawalUnits}_d \}$$

Where:

c = Transmission Customer.

M = The relevant month.

d = A given day in month M.

D = Number of days d in month M.

Import Curtailment Guarantee Credit$_{c,M}$ = The amount, in \$, that Transmission Customer c will receive for month M.

ImpCurtGuarCharge$_d$ = The sum of Import Curtailment Guarantee charges, in \$, for all Transmission Customers supplying Station Power as third-party providers for day d.

WithdrawalUnits$_{c,d}$ = The Withdrawal Billing Units, in megawatt hours, for Transmission Customer c in day d, except for Withdrawal Billing Units to supply Station Power as a third-party provider.

TotalWithdrawalUnits$_d$ = The sum, in megawatt hours, of Withdrawal Billing Units for all Transmission Customers in day d, except for the Withdrawal Billing Units to supply Station Power as third-party providers.

OATT Schedule 1 Charge – Local Reliability Bid Production Cost Guarantee Charge

Calculation of the Local Reliability Bid Production Cost Guarantee (BPCG) Charge for Transmission Customers Based on Withdrawal Billing Units Not Used to Supply Station Power under Part 5 of the NYISO OATT

The NYISO will charge, and each Transmission Customer that serves Load in the Subzone where the Resource is located will pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, a charge in accordance with the following formula for each Subzone:

Local Reliability BPCG Charge$_{c,M}$

$$= \sum_{d=1}^{D} \{ \text{BPCGCosts}_d \times \text{SZWithdrawalUnits}_{c,d} \\ \div \text{SZTotalWithdrawalUnits}_d \}$$

Where:

c = Transmission Customer.

D = Number of days (d) in the month.

M = The relevant month,

Local Reliability BPCG Charge$_{c,M}$ = The amount, in \$, for which Transmission Customer c is responsible for month M for the relevant Subzone.

BPCGCosts$_d$ = The Bid Production Cost guarantee payments, in \$, made to Suppliers for Resources for day d in the relevant Subzone arising as a result of meeting the reliability needs of that Subzone, except for the BPCG payments made to Suppliers for SCRs.

SZWithdrawalUnits$_{c,d}$ = The Withdrawal Billing Units, in megawatt hours, for Transmission Customer c in day d in the relevant Subzone, except for Withdrawal Billing Units for Wheels Through, Exports, and to supply Station Power as a third-party provider.

SZTotalWithdrawalUnits$_d$ = The sum, in megawatt hours, of Withdrawal Billing Units for all Transmission Customers in day d in the relevant Subzone, except for Withdrawal Billing Units for Wheels Through, Exports, and to supply Station Power as third-party providers.

Calculation of the Local Reliability BPCG Charge for Transmission Customers Based on Withdrawal Billing Units to Supply Station Power under Part 5 of the NYISO OATT

The NYISO will charge, and each Transmission Customer that serves Load in the Subzone where the Resource is located will pay based on its Withdrawal Billing Units used to supply Station Power as a third-party provider, a charge in accordance with the following formula for each Subzone.

Local Reliability BPCG Charge$_{c,M}$

$$= \sum_{d=1}^{N} \{ \text{BPCGCosts}_d \times \text{SZStationPower}_{c,d} \\ \div \text{SZTotalWithdrawalUnits}_d \}$$

Where:

c = Transmission Customer.

M = The relevant month.

d = A given day in month M.

N = Number of days d in month M.

Local Reliability BPCG Charge$_{c,M}$ = The amount, in \$, for which Transmission Customer c is responsible for month M for the relevant Subzone.

SZStationPower$_{c,d}$ = The Withdrawal Billing Units, in megawatt hours, of Transmission Customer c in day d that are used to supply Station Power as a third-party provider.

BPCGCosts$_d$ = The BPCG payments, in \$, made to Suppliers for Resources for day d in the relevant Subzone arising as a result of meeting the reliability needs of that Subzone, except for the BPCG payments made to Suppliers for SCRs.

SZTotalWithdrawalUnits$_d$ = The sum, in megawatt hours, of Withdrawal Billing Units for all Transmission Customers in day d in the relevant Subzone, except for Withdrawal Billing Units for Wheels Through, Exports, and to supply Station Power as third-party providers.

Calculation of the Local Reliability BPCG Credit

The NYISO will calculate, and each Transmission Customer that serves Load in the Subzone where the Resource is located will receive based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, an amount of the revenue collected through the Local Reliability BPCG charge recovered from third-party Station Power providers. This credit shall be calculated according to the following formula:

$$\text{Local Reliability BPCG Credit}_{c,M}$$
$$= \sum_{d=1}^{D} \{\text{LocRelBPCGCharge}_d \times \text{SZWithdrawalUnits}_{c,d}$$
$$\div \text{SZTotalWithdrawalUnits}_d\}$$

Where:

c = Transmission Customer.

M = The relevant month.

d = A given day in month M.

D = Number of days d in month M.

Local Reliability BPCG Credit$_{c,M}$ = The amount, in \$, that Transmission Customer c will receive for month M.

LocRelBPCGCharge$_d$ = The sum of Local Reliability BPCG charges, in \$, for all Transmission Customers that supply Power as third-party providers in the relevant Subzone as calculated above for day d.

SZWithdrawalUnits$_{c,d}$ = The Withdrawal Billing Units, in megawatt hours, for Transmission Customer c in day d in the relevant Subzone, except for Withdrawal Billing Units for Wheels Through, Exports, and to supply Station Power as a third-party provider.

SZTotalWithdrawalUnits$_d$ = The sum, in megawatt hours, of Withdrawal Billing Units for all Transmission Customers in day d in the relevant Subzone, except for Withdrawal Billing Units for Wheels Through, Exports, and to supply Station Power as third-party providers.

OATT Schedule 1 Charge – Local Reliability SCR BPCG Charge

The NYISO will recover the costs of BPCG payments incurred to compensate SCRs called to meet the reliability needs of a local system. To do so, the NYISO will charge, and each Transmission Customer that serves Load in the Subzone where the SCR is located will pay based on its Withdrawal Billing Units that are not used to provide Station Power as third-party providers, a charge in accordance with the following formula for each Subzone.

Calculation of the Local Reliability SCR BPCG Charge for Transmission Customers Based on Withdrawal Billing Units Not Used to Supply Station Power under Part 5 of the NYISO OATT

$$\text{Local Reliability SCR BPCG Charge}_{c,M}$$
$$= \sum_{d=1}^{D} \{ \text{BPCGCosts}_d \times \text{SZWithdrawalUnits}_{c,d} \div \text{SZTotalWithdrawalUnits}_d \}$$

Where:

c = Transmission Customer.

D = Number of days (d) in the month,

M = The relevant month,

Local Reliability SCR BPCG Charge$_{c,M}$ = The amount, in \$, for which Transmission Customer c is responsible for month M for the relevant Subzone.

BPCGCosts$_d$ = The BPCG payments, in \$, made to Suppliers for SCRs for day d in the relevant Subzone arising as a result of meeting the reliability needs of that Subzone.

SZWithdrawalUnits$_{c,d}$ = The Withdrawal Billing Units, in megawatt hours, for Transmission Customer c in day d in the relevant Subzone, except for Withdrawal Billing Units for Wheels Through, Exports, and to supply Station Power as a third-party provider.

SZTotalWithdrawalUnits$_d$ = The sum, in megawatt hours, of Withdrawal Billing Units for all Transmission Customers in day d in the relevant Subzone, except for Withdrawal Billing Units for Wheels Through, Exports, and to supply Station Power as third-party providers.

OATT Schedule 1 Charge – NYCA Reliability SCR BPCG Charge

The NYISO will recover the costs for BPCG payments to compensate SCRs called to meet the reliability needs of the NYCA. To do so, the NYISO will charge, and each Transmission Customer that serves Load in the NYCA will pay based on its Withdrawal Billing Units that are not used to provide Station power as a third-party provider, a charge in accordance with the following formula.

Calculation of the NYCA Reliability SCR BPCG Charge for Transmission Customers Based on Withdrawal Billing Units Not Used to Supply Station Power under Part 5 of the NYISO OATT

NYCA Reliability SCR BPCG Charge$_{c,M}$

$$= \sum_{d=1}^{D} \{ BPCGCosts_d \times WithdrawalUnits_{c,d}$$
$$\div \ TotalWithdrawalUnits_d \}$$

Where:

    c = Transmission Customer,

    D = Number of days (d) in the month,

    M = The relevant month,

    NYCA Reliability SCR BPCG Charge$_{c,M}$ = The amount, in $, for which Transmission Customer c is responsible for month M.

    BPCGCosts$_d$ = The BPCG payments, in $, made to Suppliers for SCRs called to meet the reliability needs of the NYCA for day d.

    WithdrawalUnits$_{c,d}$ = The Withdrawal Billing Units, in megawatt hours, for Transmission Customer c in day d, except for the Withdrawal Billing Units to supply Station Power as a third-party provider.

    TotalWithdrawalUnits$_d$ = The sum, in megawatt hours, of Withdrawal Billing Units for all Transmission Customers in day d, except for Withdrawal Billing Units to supply Station Power as third-party providers.

OATT Rate Schedule 1 Charge – NYCA Reliability BPCG Charge

Calculation of the NYCA Reliability BPCG Charge for Transmission Customers Based on Withdrawal Billing Units Not Used to Supply Station Power under Part 5 of the NYISO OATT

The NYISO will charge, and each Transmission Customer will pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, a charge in accordance with the following formula:

NYCA Reliability BPCG Charge$_{c,M}$

$$= \sum_{d=1}^{D} \{ BPCGCosts_d \times WithdrawalUnits_{c,d}$$
$$\div \ TotalWithdrawalUnits_d \}$$

Where:

    c = Transmission Customer,

    D = Number of days (d) in the month,

    M = The relevant month,

    NYCA Reliability BPCG Charge$_{c,M}$ = The amount, in $, for which Transmission Customer c is responsible for month M.

    BPCGCosts$_d$ = The BPCG costs, in $, for day d not recovered by the NYISO through Sections 8.1.11.1, 8.1.11.2, 8.1.11.3, 8.1.11.4, and 8.1.11.5 of this manual.

$WithdrawalUnits_{c,d}$ = The Withdrawal Billing Units, in megawatt hours, for Transmission Customer c in day d, except for the Withdrawal Billing Units to supply Station Power as a third-party provider.

$TotalWithdrawalUnits_d$ = The sum, in megawatt hours, of Withdrawal Billing Units for all Transmission Customers in day d, except for the Withdrawal Billing Units to supply Station Power as third-party providers.

Calculation of the NYCA Reliability BPCG Charge for Transmission Customers Based on Withdrawal Billing Units to Supply Station Power under Part 5 of the NYISO OATT

The NYISO will charge, and each Transmission Customer will pay based on its Withdrawal Billing Units used to supply Station Power as a third-party provider, a charge in accordance with the following formula:

$$\text{NYCA Reliability BPCG Charge}_{c,M}$$
$$= \sum_{d=1}^{D} \{ \text{BPCGCosts}_d \times \text{StationPower}_{c,d} \div \text{TotalWithdrawalUnits}_d \}$$

Where:

c = Transmission Customer.

M = The relevant month.

d = A given day in month M.

D = Number of days d in month M.

NYCA Reliability BPCG Charge$c_{,M}$ = The amount, in $, for which Transmission Customer c is responsible for month M.

$StationPower_{c,d}$ = The Withdrawal Billing Units, in megawatt hours, of Transmission Customer c in day d that are used to supply Station Power as a third-party provider.

$BPCGCosts_d$ = The BPCG costs, in $, for day d not recovered by the NYISO through Sections 8.1.11.1, 8.1.11.2, 8.1.11.3, 8.1.11.4, and 8.1.11.5 of this manual.

$TotalWithdrawalUnits_d$ = The sum, in megawatt hours, of Withdrawal Billing Units for all Transmission Customers in day d, except for the Withdrawal Billing Units to supply Station Power as third-party providers.

Calculation of the NYCA Reliability BPCG Credit

The NYISO will calculate, and each Transmission Customer will receive based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, an amount of the revenue collected through the NYCA Reliability BPCG charge recovered from third-party Station Power providers. This credit shall be calculated according to the following formula.

$$\text{NYCA Reliability BPCG Credit}_{c,M}$$

$$= \sum_{d=1}^{D} \{ \text{NYCARelBPCGCharge}_d \times \text{WithdrawalUnits}_{c,d}$$
$$\div \text{TotalWithdrawalUnits}_d \}$$

Where:

c = Transmission Customer.

M = The relevant month.

d = A given day in month M.

D = Number of days d in month M.

NYCA Reliability BPCG Credit$_{c,M}$ = The amount, in \$, that Transmission Customer c will receive for month M.

NYCARelBPCGCharge$_d$ = The sum of NYCA Reliability BPCG charges, in \$, for all Transmission Customers supplying Station Power as third-party Station Power providers for day d.

WithdrawalUnits$_{c,d}$ = The Withdrawal Billing Units, in megawatt hours, for Transmission Customer c in day d, except for the Withdrawal Billing Units to supply Station Power as a third-party provider.

TotalWithdrawalUnits$_d$ = The sum, in megawatt hours, of Withdrawal Billing Units for all Transmission Customers in day d, except for the Withdrawal Billing Units to supply Station Power as third-party providers.

OATT Schedule 1 Charge – Dispute Resolution Payment/Charge

The NYISO will calculate, and each Transmission Customer will receive or pay, a dispute resolution payment or charge in accordance with Section 8.1.12 of this manual for the distribution of funds received by the NYISO or the recovery of funds incurred by the NYISO in the settlement of a dispute.

Calculation of the Dispute Resolution Payment/Charge for Transmission Customers

$$\text{Dispute Resolution Payment/Charge}_{c,M}$$
$$= \text{DisputeResolutionCosts}_M \times \text{WithdrawalUnits}_{c,M}$$
$$\div \text{TotalWithdrawalUnits}_M$$

Where:

c = Transmission Customer.

M = The relevant month.

Dispute Resolution Payment/Charge$_{c,M}$ = The amount, in \$, for month M that (i) Transmission Customer c will receive if the NYISO is distributing funds that it has collected in the settlement of a dispute or (ii) Transmission Customer c will be responsible for if the NYISO is recovering funds that it has incurred in the settlement of a dispute.

$DisputeResolutionCosts_M$ = The amount, in \$, for month M that (i) the NYISO has collected in the settlement of a dispute or (ii) the NYISO has incurred in the settlement of a dispute.

$WithdrawalUnits_{c,M}$ = The Withdrawal Billing Units, in megawatt hours, for Transmission Customer c in month M.

$TotalWithdrawalUnits_M$ = The sum, in megawatt hours, of Withdrawal Billing Units for all Transmission Customers in month M.

OATT Schedule 1 Charge – Credit for Financial Penalties

The NYISO will distribute to each Transmission Customer on a monthly basis in accordance with the following formula any payments that it has collected from Transmission Customers to satisfy: (i) Financial Impact Charges issued pursuant to Sections 4.5.3.2 and 4.5.4.2 of the *NYISO Services Tariff*; (ii) ICAP sanctions issued pursuant to Section 5.12.12 of the *NYISO Services Tariff*; (iii) ICAP deficiency charges pursuant to Section 5.14.3.1 of the *NYISO Services Tariff*, except as provided in Section 5.14.3.2 of the *NYISO Services Tariff*; (iv) market power mitigation financial penalties pursuant to Section 23.4.3.6 of Attachment H of the *NYISO Services Tariff*, except as provided in Section 23.4.4.3.2 of Attachment H of the *NYISO Services Tariff*; and (v) any other financial penalties set forth in the *NYISO Services Tariff* or the *NYISO OATT*. The NYISO will perform this calculation separately for the allocation of the revenue from each financial penalty.

Calculation of the Credit for Financial Penalties for Transmission Customers

$$\text{Financial Penalties Credit}_{c,M} = \text{PenaltyRevenues}_M \times \text{WithdrawalUnits}_{c,M} \div \text{TotalWithdrawalUnits}_M$$

> *Where:*

c = Transmission Customer,

M = The relevant month,

Financial Penalties Credit$_{c,M}$ = The amount, in \$, that Transmission Customer c will receive for month M.

PenaltyRevenue$_M$ = The sum, in \$, of revenue that the NYISO has collected for month M from a Transmission Customer for one of the financial penalties indicated in Section 8.1.13 of this manual.

WithdrawalUnits$_{c,M}$ = The Withdrawal Billing Units, in megawatt hours, for Transmission Customer c in month M.

TotalWithdrawalUnits$_M$ = The sum, in megawatt hours, of Withdrawal Billing Units for all Transmission Customers in month M.

MST Scheduling, System Control, and Dispatch Service Charge – Annual Budget and FERC Regulatory Fee Recovery

Placeholder

MST Scheduling, System Control, and Dispatch Charge – NYISO Unbudgeted Cost Component

Placeholder

OATT Voltage Support Service Charge - LSEs NOT taking service under Section 5 of the OATT to supply Station Power and Transmission Customers engaging in Wheels Through, Exports and Purchases from the LBMP Market where the Energy is delivered to a NYCA interconnection with another Control Area

$$\sum_{1 \to d}^{D} \left\langle \begin{bmatrix} \left\{ (EVSS + PVSS) \div \left(EWU_{Annual}^{LSE} + EWU_{Annual}^{WT} + EWU_{Annual}^{EXP} + EWU_{Annual}^{LEXP} \right) \right\} \times \\ \sum_{1 \to n}^{N} \left\{ WU_{Lh}^{LSE} + WU_{Th}^{WT} + WU_{Th}^{EXP} + WU_{Th}^{LEXP} \right\} \end{bmatrix} - \\ \left[\left\{ \dfrac{\sum_{1 \to n}^{N} \left(WU_{Lh}^{LSE} + WU_{Th}^{WT} + WU_{Th}^{EXP} + WU_{Th}^{LEXP} \right) \div}{\sum_{1 \to n}^{N} \left(WU_{h}^{LSE} + WU_{h}^{WT} + WU_{h}^{EXP} + WU_{h}^{LEXP} \right)} \right\} \times SPVSS_{d}^{REV} \right] \right\rangle$$

Where:

D : Number of days (d) in the month;

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

$EVSS$: The sum of the projected NYISO payments to generation facilities and Qualified Non-Generator Voltage Support Resources providing Voltage Support Service based on Sections 15.2.2.1, 15.2.2.2, and 15.2.2.3 of Rate Schedule 2 of the NYISO Market Administration and Control Area Services Tariff (Services Tariff), expressed in dollars ($);

$PVSS$: Total of prior year payments to generation facilities and Qualified Non-Generator Voltage Support Resources supplying Voltage Support Service as defined in the NYISO Services Tariff less the total of payments received by the NYISO from Transmission Customers and LSEs in the prior year for Voltage Support Service (including all payments for penalties), expressed in dollars ($);

EWU_{Annual}^{LSE} : Forecasted annual LSE Energy Withdrawals, expressed in terms of megawatt hours;

EWU_{Annual}^{WT} : Forecasted annual Wheel-Through Transaction Energy, expressed in terms of megawatt hours;

EWU_{Annual}^{EXP} : Forecasted annual Export Transaction Energy, expressed in terms of megawatt hours;

EWU_{h}^{LEXP} : Forecasted Annual LBMP Export Energy scheduled for hour (h), expressed in terms of megawatt hours;

WU_{Lh}^{LSE} : Actual LSE Energy Withdrawal for hour (h) for LSE (L), expressed in terms of megawatt hours;

WU_{Th}^{WT} : Actual Wheel-Through Transaction megawatt hours scheduled for hour (h) for Transmission Customer (T), expressed in terms of megawatt hours;

WU_{Th}^{EXP} : Actual Export Transaction megawatt hours scheduled for hour (h) for Transmission Customer (T), expressed in terms of megawatt hours;

WU_{Th}^{LEXP} : Actual LBMP Export Energy scheduled for hour (h) for Transmission Customer (T), expressed in terms of megawatt hours;

WU_{h}^{LSE} : Total Actual LSE Energy Withdrawals NYCA-wide for hour (h), expressed in terms of megawatt hours;

WU_{h}^{WT} : Total Actual Wheel-Through Transaction megawatt hours scheduled NYCA-wide for hour (h), expressed in terms of megawatt hours;

WU_{h}^{EXP} : Total Actual Export Transaction megawatt hours scheduled NYCA-wide for hour (h), expressed in terms of megawatt hours;

WU_{h}^{LEXP} : Total Actual LBMP Export Energy scheduled NYCA-wide for hour (h), expressed in terms of megawatt hours;

$SPVSS_{d}^{REV}$: Voltage Support Service revenue collected from LSEs taking service under Section 5 of the OATT to supply Station Power in day (d), as determined below, expressed in dollars ($);

OATT Voltage Support Service Charge - LSEs taking service under Section 5 of the OATT to supply Station Power

$$\sum_{1 \to d}^{D} \left[\begin{array}{c} \left\{ (EVSS + PVSS) \div \left(EWU_{Annual}^{LSE} + EWU_{Annual}^{WT} + EWU_{Annual}^{EXP} + EWU_{Annual}^{LEXP} \right) \right\} \times \\ \sum_{1 \to n}^{N} \left\{ WU_{h}^{SPLSE} \right\} \end{array} \right]$$

Where:

D : Number of days (d) in the month;

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

$EVSS$: The sum of the projected NYISO payments to generation facilities and Qualified Non-Generator Voltage Support Resources providing Voltage Support Service based on Sections 15.2.2.1, 15.2.2.2, and 15.2.2.3 of Rate Schedule 2 of the *NYISO Services Tariff*, expressed in dollars ($);

$PVSS$: Total of prior year payments to generation facilities and Qualified Non-Generator Voltage Support Resources supplying Voltage Support Service as defined in the *NYISO Services Tariff* less the total of payments received by the NYISO from Transmission Customers and LSEs in the prior year for Voltage

Support Service (including all payments for penalties), expressed in dollars ($);

EWU_{Annual}^{LSE} : Forecasted annual LSE Energy Withdrawals, expressed in terms of megawatt hours;

EWU_{Annual}^{WT} : Forecasted annual Wheel-Through Transaction Energy, expressed in terms of megawatt hours;

EWU_{Annual}^{EXP} : Forecasted annual Export Transaction Energy, expressed in terms of megawatt hours;

EWU_{h}^{LEXP} : Forecasted Annual LBMP Export Energy scheduled for hour (h), expressed in terms of megawatt hours;

WU_{h}^{SPLSE} : Actual LSE Energy Withdrawal for LSEs taking service under Section 5 of the OATT to supply Station Power in hour (h), expressed in terms of megawatt hours;

OATT Regulation and Frequency Response Service Charge - LSEs NOT taking service under Section 5 of the OATT to supply Station Power

$$\sum_{1 \to d}^{D} \left\langle \begin{array}{l} \left[\sum_{1 \to n}^{N} \left\{ \left\{ (SRFSP_h + SRFSC_h - GPEN_h) \div \sum_{1 \to n}^{N} \left(WU_h^{LSE} \right) \right\} \times WU_{Lh}^{LSE} \right\} \right] - \\ \left[\left\{ \sum_{1 \to n}^{N} WU_{Lh}^{LSE} \div \sum_{1 \to n}^{N} WU_h^{LSE} \right\} \times SPRFS_d^{REV} \right] \end{array} \right\rangle$$

Where:

D : Number of days (d) in the month;

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

$SRFSP_h$: The sum of all Day-Ahead Market and Real-Time Market payments (including Regulation Revenue Adjustment Payments) made by the NYISO to all Suppliers of Regulation Service as described in Sections 15.3.4, 15.3.5, 15.3.6, and 15.3.7 of Rate Schedule 3 of the NYISO Services Tariff for the hour or for the day, expressed in dollars ($);

$SRFSC_h$: The sum of: (i) charges paid by all Suppliers for poor Regulation Service performance, as described in Section 15.3.5.5 and, if its provisions are re-instituted, Section 15.3.8 of Rate Schedule 3 of the NYISO Services Tariff; (ii) all real-time imbalance charges paid by Suppliers under Section 15.3.5.3 (a) of that Rate Schedule; and (iii) all Regulation Revenue Adjustment Charges assessed pursuant to Section 15.3.6 of that Rate Schedule for the hour or for the day, expressed in dollars ($);

$GPEN_h$: The sum of charges paid by Generators that do not provide Regulation Service and do not follow their RTD Base Points sufficiently accurately, as described

in Rate Schedule 3-A (Section 15.3A) of the NYISO Services Tariff for the hour or for the day, expressed in dollars ($);

WU_{Lh}^{LSE} : Actual LSE Energy Withdrawal for LSE (L) in hour (h), expressed in terms of megawatt hours;

WU_{h}^{LSE} : Total Actual LSE Energy Withdrawals NYCA-wide in hour (h), expressed in terms of megawatt hours;

$SPRFS_{d}^{REV}$: Total Regulation and Frequency Response Service revenue collected from LSEs taking service under Section 5 of the OATT to supply Station Power in day (d), as determined below, expressed in dollars ($);

OATT Regulation and Frequency Response Service Charge - LSEs taking service under Section 5 of the OATT to supply Station Power

$$\sum_{1\to d}^{D}\left\langle \left\{ \sum_{1\to n}^{N}\left(SRFSP_{h}+SRFSC_{h}-GPEN_{h}\right)\div \sum_{1\to n}^{N}WU_{h}^{LSE}\right\} \times \sum_{1\to n}^{N}WU_{h}^{SPLSE}\right\rangle$$

Where:

D : Number of days (d) in the month;

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

$SRFSP_{h}$: The sum of all Day-Ahead Market and Real-Time Market payments (including Regulation Revenue Adjustment Payments) made by the NYISO to all Suppliers of Regulation Service as described in Sections 15.3.4, 15.3.5, 15.3.6, and 15.3.7 of Rate Schedule 3 of the NYISO Services Tariff for the hour or for the day, expressed in dollars ($);

$SRFSC_{h}$: The sum of: (i) charges paid by all Suppliers for poor Regulation Service performance, as described in Section 15.3.5.5 and, if its provisions are re-instituted, Section 15.3.8 of Rate Schedule 3 of the NYISO Services Tariff; (ii) all real-time imbalance charges paid by Suppliers under Section 15.3.5.3 (a) of that Rate Schedule; and (iii) all Regulation Revenue Adjustment Charges assessed pursuant to Section 15.3.6 of that Rate Schedule for the hour or for the day, expressed in dollars ($);

$GPEN_{h}$: The sum of charges paid by Generators that do not provide Regulation Service and do not follow their RTD Base Points sufficiently accurately, as described in Rate Schedule 3-A (Section 15.3A) of the NYISO Services Tariff for the hour or for the day, expressed in dollars ($);

WU_{h}^{LSE} : Total Actual LSE Energy Withdrawals NYCA-wide in hour (h), expressed in terms of megawatt hours;

WU_{h}^{SPLSE} : Actual LSE Energy Withdrawal for LSEs taking service under Section 5 of the OATT to supply Station Power in hour (h), expressed in terms of megawatt hours;

OATT Operating Reserves Service Charge - LSEs NOT taking service under Section 5 of the OATT to supply Station Power and Transmission Customers engaging in Exports and Purchases from the LBMP Market where the Energy is delivered to a NYCA interconnection with another Control Area

$$\sum_{1 \to d}^{D} \left\langle \begin{bmatrix} \sum_{1 \to n}^{N} \left\{ \left\langle SORS_h \div \left(WU_h^{LSE} + WU_h^{EXP} + WU_h^{LEXP} \right) \right\rangle \times \left\langle WU_{Lh}^{LSE} + WU_{Th}^{EXP} + WU_{Th}^{LEXP} \right\rangle \right\} \end{bmatrix} - \\ \begin{bmatrix} \left\{ \dfrac{\sum_{1 \to n}^{N} \left(WU_{Lh}^{LSE} + WU_{Th}^{EXP} + WU_{Th}^{LEXP} \right) \div}{\sum_{1 \to n}^{N} \left(WU_h^{LSE} + WU_h^{EXP} + WU_h^{LEXP} \right)} \right\} \times SPORS_d^{REV} \end{bmatrix} \right\rangle$$

Where:

D : Number of days (d) in the month;

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

$SORS_h$: The sum of the cost to the NYISO of providing Operating Reserves in each hour to procure Operating Reserves on behalf of the market in the Day-Ahead Market and the Real-Time Market, less payments collected from entities that are scheduled to provide less Operating Reserves in the Real-Time Market than in the Day-Ahead Market during that hour, under Rate Schedule 4 (Section 15.4) of the NYISO Services Tariff, expressed in dollars ($);

WU_h^{LSE} : Total Actual LSE Energy Withdrawals NYCA-wide in hour (h), expressed in terms of megawatt hours;

WU_h^{EXP} : Total Actual Export Energy scheduled NYCA-wide in hour (h), expressed in terms of megawatt hours;

WU_h^{LEXP} : Total Actual LBMP Export Energy scheduled NYCA-wide in hour (h), expressed in terms of megawatt hours;

WU_{Lh}^{LSE} : Actual LSE Energy Withdrawal in hour (h) for LSE (L), expressed in terms of megawatt hours;

WU_{Th}^{EXP} : Total Actual Export Energy scheduled in hour (h) for Transmission Customer (T), expressed in terms of megawatt hours;

WU_{Th}^{LEXP} : Total Actual LBMP Export Energy scheduled in hour (h) for Transmission Customer (T), expressed in terms of megawatt hours;

$SPORS_d^{REV}$: Operating Reserves Service revenue collected from LSEs taking service under Section 5 of the OATT to supply Station Power in day (d), as determined below, expressed in dollars ($);

OATT Operating Reserves Service Charge - LSEs taking service under Section 5 of the OATT to supply Station Power

$$\sum_{1 \to d}^{D} \left\langle \left[\sum_{1 \to n}^{N} \left\{ \left\langle SORS_h \div \left(WU_h^{LSE} + WU_h^{EXP} + WU_h^{LEXP} \right) \right\rangle \times WU_h^{SPLSE} \right\} \right] \right\rangle$$

Where:

D : Number of days (d) in the month;

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

$SORS_h$: The sum of the cost to the NYISO of providing Operating Reserves in each hour to procure Operating Reserves on behalf of the market in the Day-Ahead Market and the Real-Time Market, less payments collected from entities that are scheduled to provide less Operating Reserves in the Real-Time Market than in the Day-Ahead Market during that hour, under Rate Schedule 4 (Section 15.4) of the NYISO Services Tariff, expressed in dollars ($);

WU_h^{LSE} : Total Actual LSE Energy Withdrawals NYCA-wide in hour (h), expressed in terms of megawatt hours;

WU_h^{EXP} : Total Actual Export Energy scheduled NYCA-wide in hour (h), expressed in terms of megawatt hours;

WU_h^{LEXP} : Total Actual LBMP Export Energy scheduled NYCA-wide in hour (h), expressed in terms of megawatt hours;

WU_{Lh}^{LSE} : Actual LSE Energy Withdrawal in hour (h) for LSE (L), expressed in terms of megawatt hours;

WU_{Th}^{EXP} : Total Actual Export Energy scheduled in hour (h) for Transmission Customer (T), expressed in terms of megawatt hours;

WU_{Th}^{LEXP} : Total Actual LBMP Export Energy scheduled in hour (h) for Transmission Customer (T), expressed in terms of megawatt hours;

WU_h^{SPLSE} : Actual LSE Energy Withdrawal for LSEs taking service under Section 5 of the OATT to supply Station Power in hour (h), expressed in terms of megawatt hours;

OATT Black Start and System Restoration Service Charge - LSEs NOT taking service under Section 5 of the OATT to supply Station Power

$$\sum_{1 \to d}^{D} \left\langle \left[\sum_{1 \to n}^{N} \left\{ \left\{ SBSRS_h \div \sum_{1 \to n}^{N} \left(WU_h^{LSE} \right) \right\} \times WU_{Lh}^{LSE} \right\} \right] - \left[\left\{ \sum_{1 \to n}^{N} WU_{Lh}^{LSE} \div \sum_{1 \to n}^{N} WU_h^{LSE} \right\} \times SBSRS_d^{REV} \right] \right\rangle$$

Where:

D : Number of days (d) in the month;

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

$SBSRS_h$: The hourly embedded cost for Black Start and System Restoration Services supplied by Generators that are part of the NYISO Plan, net of all payments forfeited due to a Generator's failure to pass a required test of its ability to provide Black Start and System Restoration Services, expressed in dollars ($);

WU_{Lh}^{LSE} : Actual LSE Energy Withdrawal for LSE (L) in hour (h), expressed in terms of megawatt hours;

WU_h^{LSE} : Total Actual LSE Energy Withdrawals NYCA-wide in hour (h), expressed in terms of megawatt hours;

$SBSRS_d^{REV}$: Total Black Start and System Restoration Service revenue collected from LSEs taking service under Section 5 of the OATT to supply Station Power in day (d), as determined below, expressed in dollars ($);

OATT Black Start and System Restoration Service Charge - LSEs taking service under Section 5 of the OATT to supply Station Power

$$\sum_{1 \to d}^{D} \left\langle \left\{ \sum_{1 \to n}^{N} SBSRS_h \div \sum_{1 \to n}^{N} WU_h^{LSE} \right\} \times \sum_{1 \to n}^{N} WU_h^{SPLSE} \right\rangle$$

Where:

D : Number of days (d) in the month;

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

$SBSRS_h$: The hourly embedded cost for Black Start and System Restoration Services supplied by Generators that are part of the NYISO Plan, net of all payments forfeited due to a Generator's failure to pass a required test of its ability to provide Black Start and System Restoration Services, expressed in dollars ($);

WU_h^{LSE} : Total Actual LSE Energy Withdrawals NYCA-wide in hour (h), expressed in terms of megawatt hours;

WU_h^{SPLSE} : Actual LSE Energy Withdrawal for LSEs taking service under Section 5 of the OATT to supply Station Power in hour (h), expressed in terms of megawatt hours;

OATT Local Black Start and System Restoration Service Charge - LSEs NOT taking service under Section 5 of the OATT to supply Station Power

$$\sum_{1 \to d}^{D} \left\langle \left[\sum_{1 \to n}^{N} \left\{ \left\{ SLBSRS_h \div \sum_{1 \to n}^{N} \left(WU_h^{LSE} \right) \right\} \times WU_{Lh}^{LSE} \right\} \right] - \left[\left\{ \sum_{1 \to n}^{N} WU_{Lh}^{LSE} \div \sum_{1 \to n}^{N} WU_h^{LSE} \right\} \times SLBSRS_d^{REV} \right] \right\rangle$$

Where:

D : Number of days (d) in the month;

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

$SLBSRS_h$: The hourly embedded cost for Black Start and System Restoration Services supplied by Generators that are part of a Transmission Owner's local Black Start and System Restoration Plan, net of all payments forfeited due to a Generator's failure to pass a required test of its ability to provide local Black Start and System Restoration Services, expressed in dollars ($);

WU_{Lh}^{LSE} : Actual LSE Energy Withdrawal for LSE (*L*) within the respective Transmission Owner's transmission district to which the local Black Start and System Restoration Plan pertains in hour (h), expressed in terms of megawatt hours;

WU_h^{LSE} : Total Actual LSE Energy Withdrawals within the respective Transmission Owner's transmission district to which the local Black Start and System Restoration Plan pertains in hour (h), expressed in terms of megawatt hours;

$SLBSRS_d^{REV}$: Total Black Start and System Restoration Service revenue collected from LSEs taking service under Section 5 of the OATT to supply Station Power within the respective Transmission Owner's transmission district to which the local Black Start and System Restoration Plan pertains in day (d), as determined below, expressed in dollars ($);

OATT Local Black Start and System Restoration Service Charge - LSEs taking service under Section 5 of the OATT to supply Station Power

$$\sum_{1 \to d}^{D} \left\langle \left\{ \sum_{1 \to n}^{N} SBSRS_h \div \sum_{1 \to n}^{N} WU_h^{LSE} \right\} \times \sum_{1 \to n}^{N} WU_h^{SPLSE} \right\rangle$$

Where:

D : Number of days (d) in the month;

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

$SLBSRS_h$: The hourly embedded cost for Black Start and System Restoration Services supplied by Generators that are part of a Transmission Owner's local Black Start and System Restoration Plan, net of all payments forfeited due to a Generator's failure to pass a required test of its ability to provide local Black Start and System Restoration Services, expressed in dollars ($);

WU_h^{LSE} : Total Actual LSE Energy Withdrawals within the respective Transmission Owner's transmission district to which the local Black Start and System Restoration Plan pertains in hour (h), expressed in terms of megawatt hours;

WU_h^{SPLSE} : Actual LSE Energy Withdrawal for LSEs taking service under Section 5 of the OATT to supply Station Power within the respective Transmission Owner's transmission district to which the local Black Start and System Restoration Plan pertains in hour (h), expressed in terms of megawatt hours;

LSE OATT Reliability Facilities Charge (RFC) Recovery

Placeholder

Appendix N.   Station Power Settlements

Station Power is defined in the NYISO Market Administration and Control Area Services Tariff (Services Tariff) as the energy "for operating electric equipment located on the Generator site, or portions thereof, owned by the same entity that owns the Generator, which electrical equipment is used by the Generator exclusively for the production of Energy and any useful thermal energy associated with the production of Energy; and for the incidental heating, lighting, air conditioning and office equipment needs of buildings, or portions thereof, that are: a. owned by the same entity that owns the Generator; b. located on the Generator site; and c. used by the Generator exclusively in connection with the production of Energy and any useful thermal energy associated with the production of Energy. Station Power does not include any Energy: (i) used to power synchronous condensers; (ii) used for pumping at a pumped storage facility; or (iii) provided during a Black Start restoration by Generators that provide Black Start Capability Service" (Services Tariff Section 2.19). Station Power may be procured in three ways:

- Self-Supply: The netting of generation output against station service load over a monthly period for the same unit or complex of units associated with the same Corporate Entity (CE).
- Remote Self-Supply: The netting of generation output against station service load over a monthly period for units owned by the same CE located remotely.
- Third-Party Supply: The net of station service load over generation output remaining after Self-Supply and Remote Self-Supply.

All Station Power is settled at wholesale generation rates. However, each Generator that consumes Third-Party Station Power will receive a rebate from the NYISO for the wholesale cost of the third-party energy that is consumed. In addition, the NYISO will charge the appropriate LSE / TO the exact amount the Generators collected as a rebate. These rebate/charge values appear on line items in the Consolidated Invoice. The Station Power monthly report contains Station Power Accounting and metering details on a generator-by-generator basis. Table N.1 summarizes all charges associated with Station Power.

Table N.1   Summary of All Charges Associated with Station Power

Station Power Type	NYISO Energy Charges	T.O. Energy Charge to Generator	NYISO Rebates Cost of Wholesale Energy Consumed	NYISO Charges LSE - T.O. Cost of Wholesale Energy Consumed	NTAC Paid by	Ancillary Services Paid by:	TSC Paid by:
Self-Supply	Wholesale	None	No	No	None	None	n/a
Remote Self-Supply	Wholesale	None	No	No	Generator	None	Generator
Third-Party Supply	Wholesale	Retail	Yes	Yes	LSE	LSE	Generator

Generators participating in the Station Power program enter their hourly forecasts for Station Power consumption; these load forecasts are used for the initial invoice. Metering Authorities

(MAs) report non-zero load data (hourly load bus data greater than zero) for all hours, regardless of a unit's status as on or off-line. If MAs do not upload their readings, the missing reading will be treated as 0 MW. These Load Bus meter readings are used for the 4-month true-up and all other subsequent invoices.

Determination of Monthly Net Generation

The NYISO determines net generation for each unit for each hour based on (i) hourly outputs (ii) the initial load forecasts and (iii) the finalized Station Power load bus meter readings. If hourly net generation is a negative value, then the unit consumed more megawatts in Station Power than it produced as energy in that hour. As a hypothetical example, Table N.2 illustrates net generation for four units for one month.

Table N.2   Sample Net Generation for Four Units for One Month

Net Generation by Unit															
HB	0	1	2	3	4	…	713	714	715	716	717	718	719	Net	Neg Net
Gen 1	10.0	8.0	-1.0	-2.0	0.0	…	0.0	-2.0	-2.0	-1.0	5.0	10.0	10.0	35.0	-8.0
Gen 2	4.0	2.0	-4.0	-5.0	0.0	…	0.0	-5.0	-4.0	-5.0	-4.0	-5.0	-4.0	-30.0	-36.0
Gen 3	-4.0	-4.0	-4.0	-4.0	0.0	…	0.0	-4.0	-4.0	-4.0	-4.0	2.0	4.0	-26.0	-32.0
Gen 4	-3.0	-3.0	-3.0	-3.0	0.0	…	0.0	-3.0	-3.0	-3.0	-3.0	4.0	8.0	-12.0	-24.0
												Owner Total:	-33.0	

> **Note:** Neg Net (negative net generation by unit) represents the monthly sum of all hourly negative readings for a unit and does not include any hourly positive readings

In Table N.2, four affiliated units combined to consume more megawatts than they generated over a month (-33 MW). In this case, all net megawatts consumed as Station Power will be considered self-supplied (or remotely self-supplied), with the exception of the 33MW that were third-party supplied.

The total net output is used to determine whether Third-Party Station Power supply took place. In this example, since the owner's total net output (-33 MW) is a negative number, some supply of Station Power by a Third-Party Station Power took place (and remote self-supply Station Power may exist). If the total net output had been a positive number in this example, there would be no Third-Party Station Power. However, the units could remote self-supply Station Power to other generators under the same CE.

Allocation of Third-Party Station Power to Net Negative Units

If it is determined that Third-Party Station Power took place, this consumption is allocated to specific units. For CEs that have negative monthly net generation (i.e., an owner's total negative net output, as in the example above), load is first allocated to the units with the greatest negative output until all of the CE's negative monthly net generation is accounted for. Using the example above, the allocation of third party-supplied Station Power to net negative units would be determined as follows in Table N.3:

Table N.3   **Sample Allocation of Third-Party Supplied Station Power to Net Negative Units**

Generator	Unit Net Gen	Allocation
1	35.0	0.0
2	-30.0	30.0
3	-26.0	3.0
4	-12.0	0.0
Owner Total:	-33.0	33.0

The 33 MW of third party-supplied Station Power would be covered first by Unit 2 since it had the greatest negative output over the month, as illustrated in Table N.4:

Table N.4   Allocation of Third-Party Station Power

Generator	Unit Net Gen	Allocation
1	35.0	0.0
2	**-30.0**	**30.0**
3	-26.0	3.0
4	-12.0	0.0
Owner Total:	-33.0	33.0

In the example illustrated in Table N.5, the absolute value of the owner's total (33MW) is greater than the Station Power consumed by Unit 2 (30MW), so all of Unit 2's monthly net generation is considered to be Third-Party Station Power. If the owner's total were less than the most negative unit's monthly net generation, the most negative unit would cover the owner's total and no further allocations of load would be necessary. After Unit 2's megawatts have been allocated, 3MW of Third-Party Station Power remain. Unit 3 (26MW) is the remaining unit with the highest negative monthly net generation and, therefore, is allocated the remaining 3MW of negative net generation. At this point, all of the CE's negative monthly net generation has been accounted for and no more Third-Party Station Power will be allocated.

Table N.5   Allocation of Remaining Third-Party Station Power

Generator	Unit Net Gen	Allocation
1	35.0	0.0
2	**-30.0**	**30.0**
3	**-26.0**	**3.0**
4	-12.0	0.0
Owner Total:	-33.0	33.0

For this example, allocating Third-Party Station Power to units with a negative net generation results in only Units 2 (30MW) and 3 (3MW) receiving Station Power as third-party supply. If the remaining megawatt load from the second allocation was greater than Unit 3's negative

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monthly net generation, then the iterative process would continue until all third-party supplied Station Power was allocated.

Remote Self Supply Station Power

After allocating Third-Party Station Power, any remaining monthly net generation is considered remotely self-supplied Station Power. For instance, in the example above, the 23MW (26MW – 3MW) consumed by Unit 3 (i.e., the megawatts not allocated to third-party supply and the 12 MW of load consumed by Unit 4 are considered to be remote self-supply Station Power. These 35 MW (23MW + 12 MW) are remotely self-supplied from the 35 MW produced by Unit 1.

Table N.6 — Remote Self-Supply Station Power Load Allocation

Remote Self-Supply Allocation				
Generator	1	2	3	4
Monthly Net Gen	35.0	-30.0	-26.0	-12.0
Allocated Third-Party Megawatt Hours	0.0	30.0	3.0	0.0
Remote Self Supply Megawatt Hours	0.0	0.0	23.0	12.0

NTAC and TSC are charged, as typically applied to normal load, for each megawatt of consumed Remote Self-Supply Station Power.

Determining the Wholesale Cost of Third-Party Station Power

After determining the type of Station Power for which units are eligible, the hourly wholesale cost is determined for units that have been allocated Third-Party Station Power. In the examples above, only Units 2 and 3 were allocated third-party station supply and only these units are allocated the associated wholesale costs.

The wholesale cost of Third-Party Station Power is determined by multiplying the hourly unit net generation (Table N.2) by the unit's allocation of third-party supply (Table N.5) and dividing by the unit's negative net generation (Table N.2). This calculation is only performed for hours that have a negative hourly unit net generation value.

For example, Unit 2 has a net generation of –5.00MW for hour 3 and an allocation of third-party supply of 30MW. Unit 2 has negative net generation totaling –36.00MWh over the month. Unit 2's Third-Party Station Power megawatt allocation for hour 3 is ((-5.00*30.000) / 36.00) = 4.167MW, as illustrated in Table N.7.

Table N.7 — Hourly Third-Party Station Power Load Allocation

HB	0	1	2	3	4	…	713	714	715	716	717	718	719	Ttl	Neg Net
Gen 1	0.0	0.0	0.0	0.0	0.0	…	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gen 2	0.0	0.0	3.333	4.167	0.0	…	0.0	4.167	3.333	4.167	3.333	4.167	3.333	30.0	-36.0
Gen 3	0.375	0.375	0.375	0.375	0.0	…	0.0	0.375	0.375	0.375	0.375	0.0	0.0	3.0	-32.0
Gen 4	0.0	0.0	0.0	0.0	0.0	…	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
												Owner Total:	33.0	

The hourly wholesale cost of Third-Party Station Power is determined by multiplying the hourly third-party megawatt allocation by the hourly Gen Bus LBMP, as illustrated in Table N.8.

Table N.8   Hourly Third-Party Station Power Costs

HB	0	1	2	3	…	714	715	716	717	718	719
Gen 1	$33.62	$28.46	$21.72	$22.54	…	$42.86	$42.58	$51.36	$45.63	$40.47	$30.12
Gen 2	$33.62	$28.46	$21.72	$22.54	…	$42.86	$42.58	$51.36	$45.63	$40.47	$30.12
Gen 3	$33.62	$28.46	$21.72	$22.54	…	$42.86	$42.58	$51.36	$45.63	$40.47	$30.12
Gen 4	$33.62	$28.46	$21.72	$22.54	…	$42.86	$42.58	$51.36	$45.63	$40.47	$30.12

For example, Unit 2 has an Hourly third-party Allocation for hour 3 of 4.167MW and a Gen Bus LBMP of $22.54. The Hourly Retail Load Adjustment $ is 4.167 * $22.54 = $93.92 (see Table N.9).

Table N.9   Hourly Third-Party Station Power Cost Allocation

HB	0	1	2	3	…	714	715	716	717	718	719	Total
Gen 1	$0.00	$0.00	$0.00	$0.00	…	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Gen 2	$0.00	$0.00	$72.41	$93.92	…	$178.58	$141.93	$214.00	$152.10	$168.63	$100.40	$1,121.97
Gen 3	$12.61	$10.67	$8.15	$8.45	…	$16.07	$15.97	$19.26	$17.11	$0.0	$0.00	$108.29
Gen 4	$0.00	$0.00	$0.00	$0.00	…	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Owner Total:												$1,230.95

The monthly wholesale cost of Third-Party Station Power is determined by aggregating the hourly Third-Party Station Power wholesale cost values for each hour during the month where a unit had a negative hourly net generation. For this example, the monthly wholesale cost of third-party Station Power for Unit 2 is $1,121.97. Participants in the Station Power program should note that in instances where Third-Party Station Power is supplied, the associated LSE / TO pays the NTAC and administers the settlement for the TSC.

Rebates and Charges for Third-Party Station Power

Each generator is paid a rebate by the NYISO for the monthly wholesale cost of the consumed Third-Party Station Power. The NYISO, in turn, charges the LSE / TO the exact amount that the Generator collected as rebates from NYISO. The LSE / TO can then charge the Generator for these third party-supplied megawatts .

As indicated in the example above, the monthly wholesale cost of Third-Party Station Power for Unit 2 is $1,121.97, which is the rebate paid to Unit 2. The rebate for Unit 3 is calculated in a likewise fashion.

The NYISO charges the LSE / TO the amount rebated to the Generator. In the above example, the amount charged to the LSE / TO for Unit 2 is $1,121.97. These charges and rebates are summarized in Table N.10.

Table N.10   Third-Party Station Power Charges and Rebates

Generator	NYISO Rebate to Generator	NYISO Charge to LSE	Energy Megawatt Hours LSE Can Charge to Gnerator
Gen 2	$1,121.97	$1,121.97	30.0
Gen 3	$108.29	$108.29	3.0