Attachment VIII

2.1 Definitions - A

Actual Energy Injections: Energy injections which are measured using a revenue-quality real-time meter.

Actual Energy Withdrawals: Energy withdrawals which are either: (1) measured with a revenue-quality real-time meter; (2) assessed (in the case of Load Serving Entities ("LSEs") serving retail customers where withdrawals are not measured by revenue-quality real-time meters) on the basis provided for in a Transmission Owner's retail access program; or (3) calculated (in the case of wholesale customers where withdrawals are not measured by revenue-quality real-time meters), until such time as revenue - quality real-time metering is available on a basis agreed upon by the unmetered wholesale customers. For purposes of the allocation of the ISO annual budgeted costs and the annual FERC fee pursuant to Rate Schedule 1 of the ISO OATT, withdrawals shall also include the absolute value of negative withdrawals by Load for behind the meter generation. For purposes of assessing TSC and NTAC, Actual Energy Withdrawals shall include the absolute value of negative injections by Energy Storage Resources in accordance with Section 2.7 of the OATT.

Adjusted Actual Load: Actual Load adjusted to reflect: (i) Load relief measures such as voltage reduction and Load Shedding; (ii) Load reductions provided by Demand Side Resources; (iii) normalized design weather conditions; (iv) Station Power delivered that is not being self supplied pursuant to Section 4.7 of the ISO Services Tariff; and (v) adjustments for Special Case Resources and EDRP.

Adjusted DMGC: The value, in MW, of a BTM:NG Resource's capability in a Capability Period, as calculated pursuant to Section 5.12.6.1.1 of this Services Tariff.

Adjusted Host Load ("AHL"): The value, in MW, of a BTM:NG Resource's Load calculated pursuant to Section 5.12.6.1.2 of this Services Tariff for the purposes of determining the Resource's Capacity.

Advance Reservation: (1) A reservation of transmission service over the Cross-Sound Scheduled Line that is obtained in accordance with the applicable terms of Schedule 18 and the Schedule 18 Implementation Rule of the ISO New England Inc. Transmission, Markets and Services Tariff, or in accordance with any successors thereto; or (2) A right to schedule transmission service over the Neptune Scheduled Line that is obtained in accordance with the rules and procedures established pursuant to Section 38 of the PJM Interconnection, L.L.C. Open Access Transmission Tariff and set forth in a separate service schedule under the PJM Interconnection, L.L.C. Open Access Transmission Tariff; or (3) A right to schedule transmission service over the Linden VFT Scheduled Line that is obtained in accordance with the rules and procedures established pursuant to Section 38 of the PJM Interconnection, L.L.C. Open Access Transmission Tariff and set forth in a separate service schedule under the PJM Interconnection, L.L.C. Open Access Transmission Tariff; or (4) A right to schedule transmission service over the HTP Scheduled Line that is obtained in accordance with the rules and procedures established pursuant to Section 38 of the PJM Interconnection, L.L.C. Open Access Transmission Tariff and set forth in a separate service schedule under the PJM Interconnection, L.L.C. Open Access Transmission Tariff.

Adverse Conditions: Those conditions of the natural or man-made environment that threaten the adequate reliability of the NYS Power System, including, but not limited to, thunderstorms, hurricanes, tornadoes, solar magnetic flares and terrorist activities.

Affiliate: With respect to a person or entity, any individual, corporation, partnership, firm, joint venture, association, joint-stock company, trust or unincorporated organization, directly or indirectly controlling, controlled by, or under common control with, such person or entity. The term "Control" shall mean the possession, directly or indirectly, of the power to direct the management or policies of a person or an entity. A voting interest of ten percent or more shall create a rebuttable presumption of control.

Ancillary Services: Services necessary to support the transmission of Energy from Generators to Loads, while maintaining reliable operation of the NYS Power System in accordance with Good Utility Practice and Reliability Rules. Ancillary Services include Scheduling, System Control and Dispatch Service; Reactive Supply and Voltage Support Service (or "Voltage Support Service"); Regulation Service; Energy Imbalance Service; Operating Reserve Service (including Spinning Reserve, 10-Minute Non-Synchronized Reserves and 30-Minute Reserves); and Black Start Capability.

Application: A request to provide or receive service pursuant to the provisions of the ISO Services Tariff, that includes all information reasonably requested by the ISO.

Automatic Generation Control ("AGC"): The **automatic** regulation of the power output of electric Generators within a prescribed range in response to a change in system frequency, or tie-line loading, to maintain system frequency or scheduled interchange with other areas within predetermined limits.

Available Generating Capacity: Generating Capacity that is on line to serve Load and/or provide Ancillary Services, or is capable of initiating start-up for the purpose of serving Transmission Customers or providing Ancillary Services, within thirty (30) minutes.

Available Operating Capacity: For purposes of determining a Scarcity Reserve Requirement, the capability of all Suppliers that are eligible to provide Operating Reserves and have submitted Energy Bids in the Real-Time Market to provide Energy in greater than 30 minutes but less than or equal to 60 minutes; provided, however, that this value shall not include any quantity of Energy and Operating Reserves scheduled to be provided by all such Suppliers. The Available Operating Capacity value (in MW) shall be calculated by the RTD software for each normal RTD run. For purposes of calculating a Scarcity Reserve Requirement in accordance with Section 15.4.6.2 of Rate Schedule 4 of this ISO Services Tariff, each RTD run shall utilize the value of Available Operating Capacity calculated during the immediately preceding normal RTD run and each RTC run shall utilize the value of Available Operating Capacity calculated during the most recently-completed normal RTD run prior to the RTC run.

Availability: A measure of time that a Generator, transmission line, interconnection or other facility is capable of providing service.

Average Coincident Host Load ("ACHL"): The value calculated for a Capability Year in accordance with Section 5.12.6.1.2.1 of this Tariff. The ACHL shall account for weather normalization and Load growth.

Average Coincident Load ("ACL"): The value in each Capability Period calculated for each Special Case Resource, except those that are eligible to report a Provisional Average Coincident Load, that is equal to the average of the SCR's metered hourly Load that is supplied by the NYS Transmission System and/or the distribution system during the Capability Period SCR Load Zone Peak Hours applicable to such SCR, and computed and reported in accordance with Section 5.12.11.1.1 of this Services Tariff and ISO Procedures. Any Load supported by generation produced from a Local Generator, other behind-the-meter generator, or other supply source located behind the SCR's meter operating during the Capability Period SCR Load Zone Peak Hours may not be included in the SCR's metered Load values reported for the ACL.

Average Coincident Load of an SCR Aggregation: The value that is equal to the sum of the Average Coincident Loads and Provisional Average Coincident Loads for all Special Case Resources in an SCR Aggregation, assigned by the Responsible Interface Party to an SCR Aggregation in a single Load Zone, computed and reported monthly in accordance with Section 5.12.11.1.4 of this Services Tariff and ISO Procedures.

2.9 Definitions - I

ICAP Demand Curve: A series of prices which decline until reaching zero as the amount of Installed Capacity increases.

ICAP Demand Curve Reset Filing Year: A calendar year in which the ISO files ICAP Demand Curves, in accordance with Section 5.14.1.2.1.11 or Section 5.14.1.2.2.4.11.

ICAP Ineligible Forced Outage: The outage state of a Market Participant's Generator after: i) the expiration or termination of its Forced Outage pursuant to the provisions in Section 5.18.1.6 of this Services Tariff, which Forced Outage started on or after May 1, 2015; ii) the Market Participant voluntarily reclassified its Forced Outage pursuant to the provisions in Section 5.18.2.1 of this Services Tariff, which Forced Outage started on or after May 1, 2015; or iii) substantial actions have been taken, such as dismantling or disabling essential equipment, which actions are inconsistent with an intention to return the Generator to operation and the Energy market. A Generator in an ICAP Ineligible Forced Outage is subject to the return-to-service provisions in Section 5.18.4 of this Services Tariff and is ineligible to participate in the Installed Capacity market.

ICAP Spot Market Auction: An auction conducted pursuant to Section 5.14.1.1 of this Tariff to procure and set LSE Unforced Capacity Obligations for the subsequent Obligation Procurement Period, pursuant to the Demand Curves applicable to each respective LSE and the supply that is offered.

Import Constrained Locality: New York City and the G-J Locality.

Import Credit Requirement: A component of the External Transaction Component of the Operating Requirement, calculated in accordance with Section 26.4.2 of Attachment K to this Services Tariff.

Import Curtailment Guarantee Payment: A payment made in accordance with Section 4.5.2.2 and Attachment J of this ISO Services Tariff to compensate a Supplier whose Import is Curtailed by the ISO.

Imports: A Bilateral Transaction or sale to the LBMP Market where Energy is delivered to a NYCA Interconnection from another Control Area.

Imputed LBMP Revenue: Revenue developed for calculating a Generator or Import Bid Production Cost guarantee, for any interval, which equals the product of (i) the Bilateral Transaction scheduled MW in the Day-Ahead Market or real-time market, as appropriate, from the Generator bus or Proxy Generator Bus, as appropriate, for the interval, (ii) the LBMP, in units of $/MWh, either Day-Ahead or real-time as appropriate, at the Generator or Proxy Generator Bus for that interval and (iii) the length of the interval, in units of hours.

Inactive Reserves: The outage state in which a Market Participant's Generator is unavailable to produce Energy for a limited period of time not to exceed six months, for reasons that are not equipment related, which state does not meet the criteria to be classified as any other outage pursuant to the provisions of this Services Tariff or of ISO Procedures. A Generator in Inactive Reserves is ineligible to participate in the Installed Capacity market.

Inadvertent Energy Accounting: The accounting performed to track and reconcile the difference between net actual Energy interchange and scheduled Energy interchange of a Control Area with adjacent Control Areas.

In-City: Located electrically within the New York City Locality (LBMP Load Zone J).

Incremental Average Coincident Load ("Incremental ACL"): Beginning with the Summer 2014 Capability Period, the amount of qualifying Load that may be added to the Average Coincident Load of a Special Case Resource. In order to qualify to use Incremental ACL the SCR must enroll with an ACL and report an increase in the Load of the facility that is supplied by the NYS Transmission System and/or distribution system that meets or exceeds the SCR Load Change Reporting Threshold in accordance with this Services Tariff. The Incremental ACL reported in a Capability Period cannot exceed one-hundred percent (100%) of the ACL that has been calculated for the SCR when it first enrolls in the Capability Period. For resources reporting an Incremental ACL, the Net Average Coincident Load shall equal the enrolled ACL plus the reported Incremental ACL less any applicable SCR Change of Status. Each resource for which a RIP reports an Incremental ACL is subject to verification subsequent to the Capability Period pursuant to reporting requirements and calculations using the SCR's metered Load values provided in Section 5.12.11.1.5 of this Services Tariff and ISO Procedures.

Incremental Energy Bid: A series of monotonically increasing constant cost incremental Energy steps that indicate the quantities of Energy for a given price that an entity is willing to supply to the ISO Administered Markets.

Incremental TCC: As defined in the ISO OATT.

Independent System Operator ("ISO"): The New York Independent System Operator, Inc., a not-for-profit corporation established pursuant to the ISO Agreement.

Independent System Operator Agreement ("ISO Agreement"): The agreement that establishes the New York ISO.

Independent System Operator/New York State Reliability Council ("ISO/NYSRC Agreement"): The agreement between the ISO and the New York State Reliability Council governing the relationship between the two organizations.

Independent System Operator-Transmission Owner Agreement ("ISO/TO Agreement"): The agreement that establishes the terms and conditions under which the Member Systems transferred to the ISO Operational Control over designated transmission facilities.

Indicative NCZ Locational Minimum Installed Capacity Requirement: The amount of capacity that must be electrically located within a New Capacity Zone, or possess an approved Unforced Capacity Deliverability Right, in order to ensure that sufficient Energy and Capacity are available in that NCZ and that appropriate reliability criteria are met.

Injection Limit: The maximum injection of a BTM:NG Resource, in MW, into the NYS Transmission System or distribution system at the BTM:NG Resources' Point of Injection. The Injection Limit for a BTM:NG Resource must be at least 1 MW.

Installed Capacity ("ICAP"): External or Internal Capacity, in increments of 100 kW, that is made-available pursuant to Tariff requirements and ISO Procedures.

Installed Capacity Equivalent: The Resource capability that corresponds to its Unforced Capacity, calculated in accordance with ISO Procedures.

Installed Capacity Marketer: An entity which has signed this Tariff and which purchases Unforced Capacity from qualified Installed Capacity Suppliers, or from LSEs with excess Unforced Capacity, either bilaterally or through an ISO-administered auction. Installed Capacity Marketers that purchase Unforced Capacity through an ISO-administered auction may only resell Unforced Capacity purchased in such auctions in the NYCA.

Installed Capacity Supplier: An Energy Limited Resource, Generator, Installed Capacity Marketer, Responsible Interface Party, Intermittent Power Resource, Limited Control Run of River Hydro Resource, municipally-owned generation, BTM:NG Resource, System Resource or Control Area System Resource that satisfies the ISO's qualification requirements for supplying Unforced Capacity to the NYCA.

Interconnection or Interconnection Points ("IP"): The point(s) at which the NYCA connects with a distribution system or adjacent Control Area. The IP may be a single tie line or several tie lines that are operated in parallel.

Interface: A defined set of transmission facilities that separate Load Zones and that separate the NYCA from adjacent Control Areas.

Interface MW - Mile Methodology: As defined in the ISO OATT.

Interim Service Provider ("ISP"): As defined in Attachment FF to the OATT.

Intermittent Power Resource: A device for the production of electricity that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by the producing device; and (3) has variability that is beyond the control of the facility owner or operator. In New York, resources that depend upon wind, solar energy or landfill gas for their fuel have been classified as Intermittent Power Resources. Each Intermittent Power Resource that depends on wind as its fuel shall include all turbines metered at a single scheduling point identifier (PTID).

Internal: An entity (e.g., Supplier, Transmission Customer) or facility (e.g., Generator, Interface) located within the Control Area being referenced. Where a specific Control Area is not referenced, internal means the NYCA.

Internal Transactions: Purchases, sales or exchanges of Energy, Capacity or Ancillary Services where the Generator and Load are located within the NYCA.

Investment Grade Customer: A Customer that meets the criteria set forth in Section 26.3 of Attachment K to this Services Tariff.

Investor-Owned Transmission Owners: At the present time these include: Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation.

ISO Administered Markets : The Day-Ahead Market and the Real-Time Market (collectively the "LBMP Markets") and any other market or auction administered by the ISO.

ISO-Committed Fixed: In the Day-Ahead Market, a bidding mode in which a Generator requests that the ISO commit and schedule it. In the Real-Time Market, a bidding mode in which a Generator, with ISO approval, requests that the ISO schedule it no more frequently than every 15 minutes. A Generator scheduled in the Day-Ahead Market as ISO-Committed Fixed will participate as a Self-Committed Fixed Generator in the Real-Time Market unless it changes bidding mode, with ISO approval, to participate as an ISO-Committed Fixed Generator. A BTM:NG Resource is not permitted to utilize the ISO-Committed Fixed bidding mode.

ISO-Committed Flexible: A bidding mode in which a Dispatchable Generator or Demand Side Resource follows Base Point Signals and is committed by the ISO. A BTM:NG Resource is not permitted to utilize the ISO-Committed Flexible bidding mode.

ISO-Managed Energy Level: A Bid parameter which when selected indicates that an Energy Storage Resource's Energy Level constraints will be directly accounted for in the optimization. *See* Section 4.2.1.3.4 of this Services Tariff.

ISO Market Power Monitoring Program: The monitoring program approved by the Commission and administered by the ISO and the Market Monitoring Unit that is designed to monitor the possible exercise of market power in ISO Administered Markets.

ISO OATT: The ISO Open Access Transmission Tariff.

ISO Procedures: The procedures adopted by the ISO in order to fulfill its responsibilities under the ISO OATT, the ISO Services Tariff and the ISO Related Agreements.

ISO Related Agreements: Collectively, the ISO Agreement, the ISO/TO Agreement, the NYSRC Agreement, the ISO/NYSRC Agreement, and the Operating Agreements.

ISO Services Tariff (the "Tariff"): The ISO Market Administration and Control Area Services Tariff.

ISO Tariffs: The ISO OATT and the ISO Services Tariff, collectively.

ISP UCAP MW: The quantity of Unforced Capacity determined by the ISO in accordance with Section 5.14.1.1 of this Services Tariff.

2.15 Definitions - O

Obligation Procurement Period: The period of time for which LSEs shall be required to satisfy their Unforced Capacity requirements. Starting with the 2001-2002 Winter Capability Period, Obligation Procurement Periods shall be one calendar month in duration and shall begin on the first day of each calendar month.

Off-Peak: The hours between 11 p.m. and 7 a.m., prevailing Eastern Time, Monday through Friday, and all day Saturday and Sunday, and NERC-defined holidays, or as otherwise decided by the ISO.

Offeror: An entity that offers to sell Unforced Capacity in an auction.

On-Peak: The hours between 7 a.m. and 11 p.m. inclusive, prevailing Eastern Time, Monday through Friday, except for NERC-defined holidays, or as otherwise decided by the ISO.

Open Access Same-Time Information System ("OASIS"): The information system and standards of conduct contained in Part 37 of the Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS.

Operating Agreement: An agreement between the ISO and a non-incumbent owner of transmission facilities in the New York Control Area concerning the operation of the transmission facilities in the form of the agreement set forth in Appendix H (Section 31.11) of Attachment Y of the OATT.

Operating Capacity: Capacity that is readily converted to Energy and is measured in MW.

Operating Committee: A standing committee of the ISO created pursuant to the ISO Agreement, which coordinates operations, develops procedures, evaluates proposed system expansions and acts as a liaison to the NYSRC.

Operating Data: Pursuant to Section 5.12.5 of this Tariff, Operating Data shall mean GADS Data, data equivalent to GADS Data, CARL Data, metered Load data, or actual system failure occurrences data, all as described in the ISO Procedures.

Operating Requirement: The amount calculated in accordance with Section 26.4.2 of Attachment K to this Services Tariff.

Operating Reserves : Capacity that is available to supply Energy or reduce demand and that meets the requirements of the ISO. The ISO will administer Operating Reserves markets, in the manner described in this Article 4 and Rate Schedule 4 of this ISO Services Tariff, to satisfy the various Operating Reserves requirements, including locational requirements, established by the Reliability Rules and other applicable reliability standards. The basic Operating Reserves products that will be procured by the ISO on behalf of the market are classified as follows:

(1) Spinning Reserve: Operating Reserves provided by Generators and Demand Side Resources that meet the eligibility criteria set forth in Rate Schedule 4 of this ISO

Services Tariff, are already synchronized to the NYS Power System, and can respond to instructions to change their output level, or reduce their Energy usage, within ten (10) minutes. Generators utilizing inverter-based energy storage technology and that otherwise meet the eligibility criteria set forth in this ISO Services Tariff may provide Spinning Reserves. Spinning Reserves may not be provided a Demand Side Resource that facilitates demand reduction using a Local Generator, unless that Local Generator utilizes inverter-based energy storage technology, or by Behind-the-Meter Net Generation Resources that are comprised of more than one generating unit that are dispatched as a single aggregate unit;

(2) 10-Minute Non-Synchronized Reserve: Operating Reserves provided by Generators, Behind-the-Meter Net Generation Resources that are comprised of more than one generating unit that are dispatched as a single aggregate unit, or Demand Side Resources, including Demand Side Resources using Local Generators, that meet the eligibility criteria set forth in Rate Schedule 4 of this ISO Services Tariff and that can be started, synchronized and can change their output level within ten (10) minutes; and

(3) 30-Minute Reserve: Synchronized Operating Reserves provided by Generators, except Behind-the-Meter Net Generation Resources that are comprised of more than one generating unit and dispatched as a single aggregate unit, and Demand Side Resources that do not facilitate demand reduction using Local Generators, or that facilitate demand reduction using a Local Generator utilizing inverter-based energy storage technology; or non-synchronized Operating Reserves provided by Generators, Behind-the-Meter Net Generation Resources that are comprised of more than one generating unit and dispatched as a single aggregate unit, or Demand Side Resources that meet the eligibility criteria set forth in Rate Schedule 4 of this ISO Services Tariff and that can respond to instructions to change their output level within thirty (30) minutes, including starting and synchronizing to the NYS Power System.

Operating Reserve Demand Curve: A series of quantity/price points that defines the maximum Shadow Price for Operating Reserves meeting a particular Operating Reserve requirement corresponding to each possible quantity of Resources that the ISO's software may schedule to meet that requirement.

Operating Study Power Flow: A Power Flow analysis that is performed at least once before each Capability Period that is used to determine each Interface Transfer Capability for the Capability Period (<u>See</u> Attachment M to the ISO OATT).

Operational Control: Directing the operation of the Transmission Facilities Under ISO Operational Control to maintain these facilities in a reliable state, as defined by the Reliability Rules. The ISO shall approve operational decisions concerning these facilities, made by each Transmission Owner before the Transmission Owner implements those decisions. In accordance with ISO Procedures, the ISO shall direct each Transmission Owner to take certain actions to restore the system to the Normal State. Operational Control includes security monitoring, adjustment of generation and transmission resources, coordination and approval of changes in transmission status for maintenance, determination of changes in transmission status for reliability, coordination with other Control Areas, voltage reductions and Load Shedding, except that each Transmission Owner continues to physically operate and maintain its facilities, including those facilities that it has agreed to operate and maintain in accordance with an operation and maintenance agreement.

Optimal Power Flow ("OPF"): As defined in the ISO OATT.

Order Nos. 888 et seq.: The Final Rule entitled Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, issued by the Commission on April 24, 1996, in Docket Nos. RM95-8-000 and RM94-7-001, as modified on rehearing, or upon appeal. (See FERC Stats. & Regs. [Regs. Preambles January 1991 - June 1996] ¶ 31,036 (1996) ("Order No. 888"), on reh'g, III FERC Stats. & Regs. ¶ 31,048 (1997) ("Order No. 888-A"), on reh'g, 81 FERC ¶ 61,248 (1997) ("Order No. 888-B"), order on reh'g, 82 FERC ¶ 61,046 (1998) ("Order No. 888-C")).

Order Nos. 889 et seq.: The Final Rule entitled Open Access Same-Time Information System (formerly Real- Time Information Networks) and Standards of Conduct, issued by the Commission on April 24, 1996, in Docket No. RM95-9-000, as modified on rehearing, or upon appeal. (See FERC Stats. & Regs. [Regs. Preambles 1991-1996] ¶ 31,035 (1996) ("Order No. 889"), on reh'g, III FERC Stats. & Regs. ¶ 31,049 (1997) ("Order No. 889-A"), on reh'g, 81 FERC ¶ 61,253 (1997) ("Order No. 889-B")).

Original Residual TCC: As defined in the ISO OATT.

Out-of-Merit: The designation of Resources committed and/or dispatched by the ISO at specified output limits for specified time periods to meet Load and/or reliability requirements that differ from or supplement the ISO's security constrained economic commitment and/or dispatch.

The ISO may also use Out-of-Merit to reduce the CSR injection Scheduling Limit and/or the CSR withdrawal Scheduling Limit to protect NYCA or local reliability. When the ISO does so the Out-of-Merit for NYCA or local reliability designation shall apply to each of the Generators that is subject to the affected CSR Scheduling Limit.

4.1 Market Services - General Rules

4.1.1 Overview

Market Services include all services and functions performed by the ISO under this Tariff related to the sale and purchase of Energy, Capacity or Demand Reductions, and the payment to Suppliers who provide Ancillary Services in the ISO Administered Markets.

4.1.2 Independent System Operator Authority

The ISO shall provide all Market Services in accordance with the terms of the ISO Services Tariff and the ISO Related Agreements. The ISO shall be the sole point of Application for all Market Services provided in the NYCA. Each Market Participant that sells or purchases Energy, including Demand Side Resources, Special Case Resources and Emergency Demand Response Program participants, sells or purchases Capacity, or provides Ancillary Services in the ISO Administered Markets utilizes Market Services and must take service as a Customer under this Tariff and enter into a Service Agreement under the Tariff, as set forth in Attachment A; each entity that withdraws Energy to supply Load within the NYCA or provides Installed Capacity to an LSE serving Load within the NYCA utilizes the Control Area Services provided by the ISO and benefits from the reliability achieved as a result of ISO Control Area Services, must take service as a Customer under this Tariff and enter into a Service Agreement under this Tariff, as set forth in Attachment A; and each entity that has its virtual bids accepted and thereby engages in Virtual Transactions and each entity that purchases Transmission Congestion Contracts, excluding Transmission Congestion Contracts that are created prior to January 1, 2010, utilizes Market Services and must take service as a Customer under this Tariff and enter into a Services Agreement under this Tariff, as set forth in Attachment A. Each Customer that utilizes Market Services also utilizes Transmission Service and shall obtain Transmission

Service under the ISO OATT.

4.1.3 Informational and Reporting Requirements

4.1.3.1 The ISO shall operate and maintain an OASIS, including a Bid/Post System that will facilitate the posting of Bids to supply Energy, Ancillary Services and Demand Reductions by Suppliers for use by the ISO and the posting of Locational Based Marginal Prices ("LBMP") and schedules for accepted Bids for Energy, Ancillary Services and Demand Reductions. The Bid/Post System will be used to post schedules for Bilateral Transactions. The ISO will provide historical data regarding Energy and Capacity market clearing prices in addition to Congestion Costs on a publicly accessible portion of its OASIS.

4.1.3.2 Zonal Uplift Report. The ISO shall post on a publicly accessible portion of its website, in machine-readable format, a report on total daily uplift dollars paid to (a) Generators and Demand Side Resources located in Load Zones H, I and J collectively, (b) Generators and Demand Side Resources located in each of the other NYCA Load Zones, and (c) Suppliers scheduling Imports at a Proxy Generator Bus, no more than 20 calendar days after the conclusion of each month. The report shall be updated at the time the Resource-Specific Uplift Report is posted, and again approximately 120 days after an initial invoice was issued for a month, to incorporate updated information. The report shall provide the uplift paid for each month, by day and by billing category.

Costs that the ISO will report as uplift include: (1) Day-Ahead and real-time Bid Production Cost guarantee payments to Generators and to Demand Side Resource aggregations; (2) Day-Ahead Bid Production Cost guarantee payments to Suppliers that schedule Imports; (3) Day-Ahead Margin Assurance Payments; (4) cost recovery for units responding to Local Reliability Rules addressing loss of Generator gas supply; (5) Import Curtailment Guarantee Payments to Suppliers that schedule Imports in real-time; and (6) Lost Opportunity Cost payments to Suppliers of Voltage Support Service.

4.1.3.3 Resource-Specific Uplift Report. The ISO shall post on a publicly accessible portion of its website, in machine-readable format, a report on total uplift paid to Generators, Demand Side Ancillary Service Program Resources, Day-Ahead Demand Response Program resources or aggregations, and to Special Case Resource aggregations**,** on a monthly basis. The report shall provide the total uplift payment across all uplift categories paid to each Generator or aggregation of Demand Side Resources. The report shall be posted no more than 90 calendar days after the conclusion of each month and shall be updated approximately 120 days after an initial invoice was issued for the month, to incorporate updated information.

4.1.3.4 Operator-Initiated Commitment Report. The ISO shall post on a publicly accessible portion of its website, in machine-readable format, commitments made after the Day-Ahead Market for a reason other than minimizing the total production cost of serving load.

For each reported commitment, the ISO shall provide the following information:

(a) commitment size: provide both the resource's UOL_N and the quantity of MW committed;

(b) location: the Load Zone in which the resource is located;

(c) commitment reason: (i) system-wide capacity need, or (ii) constraint management, or (iii) voltage support; and

(d) commitment start time.

Operator-initiated commitments are ordinarily posted in real-time as they occur. All operator-initiated commitments for a calendar month will be available no more than 30 days after the conclusion of that month. Operator-initiated commitment postings may later be updated to improve accuracy.

4.1.4 Scheduling Prerequisites

Pursuant to ISO Procedures, each Transaction offered in the Energy, Installed Capacity, Ancillary Services or Transmission Congestion Contract market shall be subject to a minimum size of one (1) megawatt ("MW"); provided however, the minimum size of each Transaction offered in the Energy, Installed Capacity or Ancillary Services market on behalf of Energy Storage Resources shall be one tenth (0.1) of one MW. Regulation Service may be offered in tenths of a MW. Pursuant to ISO Procedures, Special Case Resources may offer a minimum of 100 kW of Unforced Capacity in the Installed Capacity Market. Each Transaction above one (1) megawatt may be scheduled in tenths of a megawatt provided, however, Bilateral Transactions and External Transactions in the LBMP Market must be bid and scheduled in increments of one (1) megawatt.

4.1.5 Communication Requirements for Market Services

Customers and Transmission Customers shall utilize Internet service providers to access the ISO's OASIS and bid/post system. Customers shall arrange for and maintain all communications facilities for the purpose of communication of commercial data to the ISO. Each Customer shall be the customer of record for the telecommunications facilities and services its uses and shall assume all duties and responsibilities associated with the procurement, installation and maintenance of the subject equipment and software.

4.1.6 Customer Responsibilities

All purchasers in the Day-Ahead or Real-Time Markets who withdraw Energy within the NYCA to serve Load or at an NYCA Interconnection with another Control Area must obtain Transmission Service under the ISO OATT. All Customers requesting service under the ISO Services Tariff to engage in Virtual Transactions must obtain Transmission Service under the ISO OATT.

All LSEs serving Load in the NYCA must comply with the Installed Capacity requirements set forth in Article 5 of this ISO Services Tariff.

All Customers taking service under the ISO Services Tariff must pay the Market Administration and Control Area Services Charge, as specified in Rate Schedule 1 of this ISO Services Tariff.

A Supplier with a Generator or Demand Side Resource with a real time physical operating problem that makes it impossible for the Generator or Demand Side Resource (a) to operate in the bidding mode in which it was scheduled, or (b) to provide all of the Energy or Ancillary Services offered in its Bids, or (c) to achieve or comply with applicable operating parameters or other requirements, shall notify the ISO.

4.1.7 Customer Compliance with Laws, Regulations and Orders

All Customers shall comply with all applicable federal, state and local laws, regulations and orders, including orders from the ISO.

4.1.7.1 Violations of FERC's orders, rules and regulations also violate this Section 4.1.7 of the ISO Services Tariff. In particular, if FERC or a court of competent jurisdiction determines there has been a violation of FERC's regulations related to electric energy market manipulation (see 18 C.F.R. Section 1c.2, or any successor provision thereto), such violation is also a violation of this ISO Services Tariff if such violation affects or is related to the ISO Administered Markets.

4.1.7.2 If the ISO becomes aware that a Customer may be engaging in, or might have engaged in, electric energy market manipulation, it shall promptly inform its Market Monitoring Unit.

4.1.7.3 This Section 4.1.7 of the ISO Services Tariff does not independently empower the ISO or its Market Monitoring Unit to impose penalties for, or to provide a remedy for, violations of FERC's prohibition against electric energy market manipulation, or for other violations of the ISO's Tariffs.

4.1.8 Commitment for Reliability

Suppliers with generating units committed by the ISO for service to ensure NYCA reliability or local system reliability, except for Behind-the-Meter Net Generation Resources and Energy Storage Resources, will recover startup and minimum generation costs that were not bid, that were not known before the close of the Real-Time Scheduling Window, and that were not recovered in the Dispatch Day, provided however, eligibility to recover such additional costs shall not be available for megawatts scheduled Day-Ahead. Payment for such costs shall be determined, as if bid, pursuant to the provisions of Attachment C of this Tariff. Payments for securing NYCA reliability and local system reliability shall be recovered by the ISO in accordance with Rate Schedule 1 of the ISO OATT.

External Installed Capacity Suppliers that respond to an SRE request are eligible to recover the ISO-verified costs they incur to respond to the SRE request to the extent such costs exceed the ISO-verified market revenues the External Installed Capacity Supplier receives. It is the obligation of the External Installed Capacity Supplier to demonstrate its costs and revenues to the ISO's satisfaction. In verifying the costs of External Installed Capacity Suppliers that respond to an SRE, the ISO will consider the incremental net costs the Market Party incurred to respond to the SRE. Recoverable costs could include, but are not limited to, incremental costs of generating to supply Energy using the requested Installed Capacity, and the incremental costs incurred by the Market Party to transmit Energy from the External Installed Capacity Supplier's resource to the NYCA, including the opportunity cost associated with lost expected revenue. However, losses resulting from the difference in External Transaction settlement prices between an External Control Area and the NYCA will only be recoverable if and to the extent the following conditions are satisfied: (a) the losses are demonstrated to be reasonably related to responding to the SRE request; and (b)(i) a counterflow Export from the NYCA offered by the Market Party at the External Interface where the Capacity delivery obligation applies is not scheduled due to NYCA reliability concerns or is curtailed to address NYCA reliability concerns, or (ii) no opportunity exists to schedule a counterflow Export from the NYCA at the External Interface where the Capacity delivery obligation applies. Payments for securing NYCA reliability and local system reliability shall be recovered by the ISO as *DisputeResolutionCosts* in accordance with Section 6.1.13 of Rate Schedule 1 of the ISO OATT.

Re-dispatching costs incurred as a result of reductions in Transfer Capability caused by Storm Watch ("Storm Watch Costs") shall be aggregated and recovered on a monthly basis by the ISO exclusively from Transmission Customers in Load Zone J. The ISO shall calculate Storm Watch Costs by multiplying the real-time Shadow Price of any binding constraint associated with a Storm Watch, by the higher of (a) zero; or (b) the scheduled Day-Ahead flow across the constraint minus the actual real-time flow across the constraint.

4.1.9 Cost Recovery for Units Responding to Local Reliability Rules Addressing Loss of Generator Gas Supply

4.1.9.1 Eligibility for Cost Recovery

Generating units designated pursuant to the New York State Reliability Council's Local Reliability Rule addressing the Loss of Generator Gas Supply for Generators located in New York City or the Local Reliability Rule addressing the Loss of Generator Gas Supply for Generators located on Long Island, as being required either to burn an alternate fuel at designated minimum levels, or to activate their auto-swap capability, based on forecast Load levels in Load Zones J and K (for purposes of this Section 4.1.9, "Eligible Units"), shall be eligible to recover costs associated with burning the required alternate fuel when one of the specified Local Reliability Rules is invoked. For purposes of this Section 4.1.9, the periods of time in which the Eligible Unit burns the alternate fuel only because one of the Local Reliability Rulesaddressing the loss of gas supply for Generators located in New York City or on Long Island has been invoked, including that period of time required for an Eligible Unit to move into and out of compliance with a Local Reliability Rule addressing the Loss of Generator Gas Supply, shall be referred to as the "Eligibility Period."

4.1.9.1.1 Obligation to Test Automatic Fuel Swap Capability and Eligibility to Recover Costs of Performing Fuel Swap Tests

Combined cycle Generating units designated pursuant to the New York State Reliability Council's Local Reliability Rules addressing the Loss of Generator Gas Supply for Generators located in New York City, which have the ability to automatically swap from natural gas to a liquid fuel source in the event of the sudden interruption of gas fuel supply or loss of gas pressure or the unavailability of gas supply to the Generator, shall:

(a) develop test procedures that are consistent with the requirements of the applicable Local Reliability Rule and ISO Procedures; and

(b) successfully test to demonstrate that the designated combined cycle units are able to automatically swap from natural gas to a liquid fuel source each Capability Period.

The requirement to perform a test each Capability Period can be met by performing a real-time automatic fuel swap, if that fuel swap was successful and occurred during the relevant Capability Period. The scheduling of a test to demonstrate that a designated combined cycle unit is able to automatically swap from natural gas to a liquid fuel source in real-time operations shall be coordinated with the ISO and with the Transmission Owner in whose subzone the Generator is located, consistent with ISO Procedures.

The period during which combined cycle Eligible Units are performing scheduled automatic fuel swap testing, including that period of time required for an Eligible Unit to move into and out of compliance with a Local Reliability Rule addressing the Loss of Generator Gas Supply, is an "Eligibility Period."

4.1.9.2 Variable Operating Cost Recovery

For Eligibility Periods, Eligible Units burning an alternate fuel that would not have been burned but for Local Reliability Rules addressing the loss of gas supply for Generators located in New York City or on Long Island being invoked and Eligible Units burning an alternate fuel because they activated their auto-swap capability and experienced a swap to the alternate fuel that would not have occurred but for the operation of the auto-swap capability in accordance with the implementation of the Local Reliability Rules addressing the loss of gas supply for

Generators located in New York City or on Long Island shall recover costs that vary with the amount of alternate fuel burned ("variable operating costs") if: (i) such costs are not reflected in the reference level for that Eligible Unit for the hours included in the Eligibility Period, pursuant to ISO Procedures, and (ii) the hour is one for which the commodity cost of the alternate fuel including taxes and emission allowance costs is greater than the commodity cost for natural gas, including taxes and emission allowance costs, as determined by the ISO. These relative commodity cost determinations shall use the same indices used by the ISO to establish daily Reference Levels. Variable operating costs shall include the commodity cost, associated taxes and emission allowance costs, of the required alternate fuel burned during an Eligibility Period pursuant to Local Reliability Rules addressing the loss of gas supply for Generators located in New York City or on Long Island. The owner or bidder of an Eligible Unit shall notify the ISO when variable operating costs change due to a change in tax rates.

4.1.9.3 Additional Cost Recovery

An Eligible Unit that seeks to recover costs incurred in connection with its compliance with Local Reliability Rules addressing the loss of gas supply for Generators located in New York City or on Long Island, in addition to the commodity cost, associated taxes and emission allowance cost recovery specified in Section 4.1.9.2, shall negotiate an Implementation Agreement with the ISO. The Eligible Unit and the ISO shall consult with and consider the input of the New York State Public Service Commission, and the Transmission Owner designated by the applicable Local Reliability Rule addressing the loss of gas supply for Generators located in New York City or on Long Island. Such Implementation Agreements shall specify, among other terms and conditions, the facilities (or portions of facilities) used to meet obligations under the Local Reliability Rule addressing the loss of gas supply for Generators located in New York City or on Long Island. The Implementation Agreement shall indicate the rate to be charged during the period of the Implementation Agreement to recover such additional costs.

The Implementation Agreement may also include costs in addition to commodity cost, associated taxes and emission allowance costs of the alternate fuel incurred in connection with compliance with Local Reliability Rules addressing the loss of gas supply for Generators located in New York City or on Long Island that vary with the amount of alternate fuel burned because a Local Reliability Rule addressing the loss of gas supply was invoked. These variable costs shall be paid pursuant to Section 4.1.9.2 as variable operating costs so as to not duplicate payments.

Each such Implementation Agreement shall have a duration of one or more Capability Periods and shall commence at the beginning of a Capability Period unless another date is approved by the Commission. If the Eligible Unit and the ISO reach agreement on the terms and conditions of the Implementation Agreement, the ISO shall file it with the Commission for its review and acceptance.

In the event that the Eligible Unit and the ISO have not come to an agreement six months prior to the beginning of the Capability Period that the Implementation Agreement is intended to govern, then either one of them may request the assistance of the Commission's Dispute Resolution Service. If the Dispute Resolution Service agrees to provide its assistance the Eligible Unit and the ISO shall participate in whatever dispute resolution process the Dispute Resolution Service may recommend. The Commission's Dispute Resolution Service may include other stakeholders to the extent confidentiality protections are in place. If, however, there is no agreement four months prior to the beginning of the relevant Capability Period then the Eligible Unit and the ISO may each file an unexecuted Implementation Agreement for the Commission's review and acceptance.

In the event that any provisions of this Section 4.1.9 are modified prior to the termination date of any Commission-accepted Implementation Agreement, such Implementation Agreement will remain in full force and effect until it expires in accordance with its contractual terms and conditions.

Rules for establishing Eligibility Periods shall be specified in ISO Procedures.

4.1.9.4 Billing

Payments made by the ISO to the Eligible Unit to pay variable operating costs and to pay the rate established by the Implementation Agreement pursuant to this Section 4.1.9 shall be in addition to any LBMP, Ancillary Service or other revenues received as a result of the Eligible Unit's Day-Ahead or Real-Time dispatch for that day. Payment by the ISO of variable operating costs pursuant to Section 4.1.9.2 shall be based on the Eligibility Period, quantity of alternate fuel burned, and relative costs of alternate fuel compared to natural gas. Payment by the ISO of the rate established in the Implementation Agreement for costs incurred other than variable operating costs shall be made as part of the ISO billing cycle regardless of which Local Reliability Rule addressing the loss of gas supply an alternate fuel is burned pursuant to, and regardless of the relative cost of the alternate fuel compared to natural gas reflected in reference levels.

4.1.9.5 Other Provisions

The ISO shall make available for the Transmission Owner in whose subzone the Generator is located: (i) the identity of Generators determined by the ISO to be eligible to recover the costs associated with burning the required alternate fuel pursuant to the provisions of this Section 4.1.9; (ii) the start and stop hours for each claimed Eligibility Period and (iii) the amount of alternate fuel for which the Generator has sought to recover variable operating costs.

4.1.10 Reserved for Future Use

4.1.11 Dual Participation

Effective May 1, 2020, Generators and Demand Side Resources electrically located in the NYCA may simultaneously participate in the ISO-administered wholesale markets and in programs or markets operated to meet the needs of distribution systems located in the NYCA. Generators, and Demand Side Resources engaged in dual participation must meet all applicable rules and obligations set forth in the ISO Tariffs.

Generators, and Demand Side Resources operating to meet an obligation outside of the ISO-administered wholesale markets must Bid in a manner that ensures they will be dispatched by the ISO for the market intervals consistent with the manner in which the Resource operates to meet such obligation(s). The ISO and Transmission Owners shall coordinate scheduling and dispatch for all Generators, and Demand Side Resources engaged in Dual Participation in accordance with ISO Procedures. The ISO has the authority to determine schedules for these resources.

4.2 Day-Ahead Markets and Schedules

4.2.1 Day-Ahead Load Forecasts, Bids and Bilateral Schedules

4.2.1.1 General Customer Forecasting and Bidding Requirements

Subject to the two earlier submission deadlines set forth below, by 5 a.m. on the day prior to the Dispatch Day: (i) All LSEs serving Load in the NYCA shall provide the ISO with Load forecasts for the Dispatch Day and the day after the Dispatch Day; and (ii) Customers and Transmission Customers submitting Bids in the Day-Ahead Market shall provide the ISO, consistent with ISO Procedures:

a. Bids to supply Energy, including Bids to supply Energy in Virtual Transactions;

b. Bids to supply Ancillary Services;

c. Requests for Bilateral Transaction schedules;

d. Bids to purchase Energy, including Bids to purchase Energy in Virtual Transactions and Bids to withdraw Energy by Withdrawal-Eligible Generators;

e. Demand Reduction Bids; and

f. For Behind-the-Meter Net Generation Resources, the forecasted Host Load for each hour of the Dispatch Day.

By 4:50 a.m. on the day prior to the Dispatch Day, all Customers or Transmission Customers shall submit Bids for External Transactions at the Proxy Generator Bus associated with the Cross-Sound Scheduled Line, the Neptune Scheduled Line, the Linden VFT Scheduled Line, or the HTP Scheduled Line.

By 4:45 a.m. on the day prior to the Dispatch Day, all Customers or Transmission Customers shall submit Bids that include revised fuel type or fuel price information to the ISO's Market Information System.

In general, the information provided to the ISO shall include the following:

4.2.1.2 Load Forecasts

The Load forecast shall indicate the predicted level of Load in MW by Point of Withdrawal for each hour.

4.2.1.3 Bids by Suppliers Using the ISO-Committed Flexible, Self-Committed Flexible or ISO-Committed Fixed Bid Modes to Supply Energy and/or Ancillary Services

4.2.1.3.1 General Rules

Day-Ahead Bids by Suppliers using the ISO-Committed Flexible, Self-Committed Flexible or ISO-Committed Fixed bid modes shall identify the Capacity, in MW, available for commitment in the Day-Ahead Market (for every hour of the Dispatch Day) and the price(s) at which the Supplier will voluntarily enter into dispatch commitments. If the Supplier elects to participate in the Day-Ahead Market, and is within a defined electrical boundary, electrically interconnected with, and routinely serves a Host Load (which Host Load does not consist solely of Station Power) at a single PTID, it can only participate in the Day-Ahead Market as a Behind-the-Meter Net Generation Resource. If the Supplier is a Behind-the-Meter Net Generation Resource, the ISO shall only consider price-MW pairs in excess of the forecasted Host Load for the Resource.

A Supplier's Day-Ahead Bids for an Energy Storage Resource to withdraw Energy and to inject Energy shall be submitted as a single, continuous, bid curve representing the Capacity, in MW, available for commitment in the Day-Ahead Market for each hour of the Dispatch Day, and shall indicate whether the Resource's Energy Level will be ISO- or Self-Managed. An Energy Storage Resource may not change its Energy Level Management election within the Day-Ahead Market evaluation period (*i.e.*, within a single day).

Co-located Storage Resources can each offer all of their available capability into the Day-Ahead Market. The ISO will account for the CSR Scheduling Limits in the scheduled if issues to CSR Generators.

If the Supplier using the ISO-Committed Flexible or Self-Committed Flexible bid mode is eligible to provide Regulation Service or Operating Reserves under Rate Schedules 3 and 4 respectively of this ISO Services Tariff, the Supplier's Bid may specify the quantity of Regulation Capacity it is making available and shall specify an emergency response rate that determines the quantity of Operating Reserves that it is capable of providing. Offers to provide Regulation Service and Operating Reserves must comply with the rules set forth in Rate Schedules 3 and 4 of this ISO Services Tariff. If a Supplier that is eligible to provide Operating Reserves does not submit a Day-Ahead Availability Bid for Operating Reserves, its Day-Ahead Bid shall be rejected in its entirety. A Behind-the-Meter Net Generation Resource that is comprised of more than one generating unit that is dispatched as a single aggregate unit at a single PTID is not qualified to provide Regulation Service or Spinning Reserves. A Supplier may resubmit a complete Day-Ahead Bid, provided that the new Bid is timely. See Section 4.2.1.9 for bidding requirements for Demand Side Resources offering Energy in the Day-Ahead Market.

Suppliers other than Demand Side Resources entering a Bid into the Day-Ahead Market may also enter Day-Ahead Bids for each of the next nine (9) Dispatch Days. If not subsequently modified or withdrawn, these offers for subsequent Dispatch Days may be used by the ISO as offers from these Suppliers in the Day-Ahead Market for these subsequent Dispatch Days. For Suppliers that are providing Unforced Capacity in the ISO-administered ICAP Market for the month in which the Dispatch Day and the nine-day advance bidding period are encompassed, the

ISO may enter the eighth day offer as the Bid for that Supplier's ninth day, if there is, otherwise no ninth–day Bid.

4.2.1.3.2 Bid Parameters

Day-Ahead Bids by Suppliers using the ISO-Committed Flexible, Self-Committed Flexible or ISO-Committed Fixed bid modes may identify-variable Energy price Bids, consisting of up to eleven monotonically increasing, constant cost incremental Energy steps, and other parameters described in ISO Procedures. Day-Ahead Bids from Demand Side Resources offering Operating Reserves or Regulation Service shall be ISO-Committed Flexible and shall have an Energy Bid price no lower than the Monthly Net Benefit Offer Floor. Day-Ahead Bids by Intermittent Power Resources that depend on wind or solar energy as their fuel shall be ISO-Committed Flexible and shall include a Minimum Generation Bid of zero megawatts and zero costs and a Start-Up Bid of zero cost.

Day-Ahead Bids by ISO-Committed Fixed and ISO-Committed Flexible Generators, other than Bids from Intermittent Power Resources that depend on wind or solar energy as their fuel, shall also include Minimum Generation Bids and hourly Start-Up Bids. Bids shall specify whether a Supplier is offering to be ISO-Committed Fixed, ISO-Committed Flexible, Self-Committed Fixed, or Self-Committed Flexible.

Co-located Storage Resources must each submit a CSR injection Scheduling Limit and a CSR withdrawal Scheduling Limit for each hour of the Day-Ahead Market to indicate the expected capability of the relevant facilities. An Energy Storage Resource that participates in a CSR shall not submit Day-Ahead Market Bids that would Self-Commit the Generator to inject or to withdraw a quantity of Energy that exceeds an applicable CSR Scheduling Limit.

4.2.1.3.3 Upper Operating Limits, Lower Operating Limits, and Response Rates

All Bids to supply Energy and Ancillary Services must specify a UOL_N and a UOL_E for each hour. A Resource's UOL_E may not be lower than its UOL_N. Bids from Withdrawal-Eligible Generators shall also specify the Generator's Lower Operating Limit for each hour.

Bids from Suppliers for Generators supplying Energy and Ancillary Services must specify a normal response rate and may provide up to three normal response rates provided the minimum normal response rate may be no less than one percent (1%) of the Generator's Operating Capacity per minute. All Bids from Suppliers for Generators supplying Energy and Ancillary Services must also specify an emergency response rate which shall be equal to or greater than the maximum normal response rate of the Generator.

Bids from Suppliers offering Operating Reserves or Regulation Service from Demand Side Resources must specify a normal response rate and an emergency response rate provided that the emergency response rate may not be lower than the normal response rate. For Demand Side Resources the minimum acceptable response rate is one percent (1%) of the quantity of Demand Reduction the Demand Side Resource produces per minute.

4.2.1.3.4 Additional Parameters for Energy Storage Resources

In addition to the parameters that Suppliers submit for Energy Storage Resources because they are Generators, specific parameters may apply to some Bids for Energy Storage Resources. Consistent with the ISO Procedures, Bids from Suppliers for Energy Storage Resources supplying Energy and Ancillary Services may be required to specify the Beginning Energy Level and the Energy Storage Resource's Roundtrip Efficiency, and must specify its Upper and Lower Storage Limits. The Energy Level for an Energy Storage Resource shall be managed by the Supplier unless the Supplier elects, in its Bids, to be ISO-Managed.

The Day-Ahead Schedule for Energy Storage Resources with ISO-Managed Energy Levels will reflect the Resource's Energy Level constraints, including the Beginning Energy Level, the Upper and Lower Storage Limits, and the Resource's Roundtrip Efficiency. An Energy Storage Resource that self-manages its Energy Level is obligated to submit Bids that are consistent with its Energy Level constraints, and the Day-Ahead optimization will not honor the above-identified Energy Level constraints.

4.2.1.4 Offers to Supply Energy from Self-Committed Fixed Generators

Self-Committed Fixed Generators shall provide the ISO with a schedule of their expected Energy output and withdrawals (when applicable) for each hour. Self-Committed Fixed Generators are responsible for ensuring that any hourly changes in output are consistent with their response rates. Self-Committed Fixed Generators shall also submit UOL_Ns, UOL_Es and variable Energy Bids for possible use by the ISO in the event that RTD-CAM initiates a maximum generation pickup, as described in Section 4.4.3 of this ISO Services Tariff.

4.2.1.5 Bids to Supply Energy in Virtual Transactions

Customers submitting Bids to supply Energy in Virtual Transactions shall identify the Energy, in MW, available in the Day-Ahead Market (for every hour of the Dispatch Day) and the price(s) at which the Customer will voluntarily make it available.

4.2.1.6 Bids to Purchase Energy in Virtual Transactions

Customers submitting bids to purchase Energy in Virtual Transactions shall identify the Energy, in MW, to be purchased in the Day-Ahead Market (for every hour of the Dispatch Day) and the price(s) at which the Customer will voluntarily purchase it.

4.2.1.7 Bilateral Transactions

Transmission Customers requesting Bilateral Transaction schedules shall identify hourly Transaction quantities (in MW) by Point of Injection and Point of Withdrawal, minimum run times associated with Firm Point-to-Point Transmission Service, if any, and shall provide other information (as described in ISO Procedures). Like other Generators, an Energy Storage Resource's bus can be the Point of Injection for a Bilateral Transaction, but it cannot be the Point of Withdrawal for a Bilateral Transaction.

4.2.1.8 Bids to Purchase LBMP Energy in the Day-Ahead Market

Each purchaser shall submit Bids indicating the hourly quantity of Energy, in MW, that it will purchase from the Day-Ahead Market for each hour of the following Dispatch Day. These Bids shall indicate the quantities to be purchased by Point of Withdrawal. The Bids may identify prices at which the purchaser will voluntarily enter into the Transaction.

4.2.1.9 Day-Ahead Bids from Demand Reduction Providers and DSASP Providers to Supply Energy from Demand Reductions

Demand Reduction Providers and DSASP Providers offering Energy from Demand Side Resources shall submit Bids: (i) identifying the amount of Demand Reduction, in MWs in accordance with Section 4.1.4, that is available for commitment in the Day-Ahead Market (for every hour of the dispatch day) and (ii) identifying the prices at which the Demand Reduction Provider or DSASP Provider will voluntarily enter into dispatch commitments to reduce demand; provided, however, the price at which the Demand Reduction Provider or DSASP Provider will voluntarily enter into dispatch commitments to reduce demand shall be no lower than the Monthly Net Benefit Offer Floor, as determined in accordance with this section. The Bids will identify the minimum period of time that the Demand Reduction Provider or DSASP Provider is willing to reduce demand, however the minimum period may not be less than one hour. The Bid may separately identify the Demand Reduction Provider's Curtailment Initiation Cost. Demand Reduction Bids from Demand Reduction Providers that are not accepted in the Day-Ahead Market shall expire at the close of the Day-Ahead Market.

The ISO shall perform the Net Benefits Test and post on its web site the Monthly Net Benefit Offer Floor for each month by the 15th of the preceding month in accordance with ISO Procedures. The Net Benefits Test shall establish the threshold price below which the dispatch of Energy from Demand Side Resources is not cost-effective. The Net Benefits Test shall consist of the following steps: (1) the ISO shall compile hourly supply curves for the Reference Month; (2) the ISO shall develop the average supply curve for the Study Month by updating the Reference Month supply curves for retirements and new entrants, and adjusting offers for changes in fuel prices; (3) the ISO shall apply an appropriate mathematical formula to smooth the average supply curve; and (4) the ISO shall evaluate the smoothed average supply curve to determine the Monthly Net Benefit Floor for the Study Month. The ISO shall apply the Monthly Net Benefit Offer Floor, as so calculated, to Bids submitted by Demand Response Providers for all hours in the Study Month.

The ISO shall promptly post corrections, where necessary, to the Monthly Net Benefit Offer Floor. Corrections shall only apply to errors in conducting the calculations described above and/or in posting the properly calculated Monthly Net Benefit Offer Floor. Corrections shall not include recalculations based on changes in gas prices as set forth above. The ISO shall not use any correction to the Monthly Net Benefit Offer Floor to determine revised Day-Ahead Market clearing prices for periods prior to the imposition of the correction.

4.2.2 ISO Responsibility to Establish a Statewide Load Forecast

By 8 a.m., or as soon thereafter as is reasonably possible, the ISO will develop and publish its statewide Load forecast on the OASIS. The ISO will use this forecast to perform the SCUC for the Dispatch Day.

4.2.3 Security Constrained Unit Commitment ("SCUC")

Subject to ISO Procedures and Good Utility Practice, the ISO will develop a SCUC schedule over the Dispatch Day using a computer algorithm which simultaneously minimizes the total Bid Production Cost of: (i) supplying power or Demand Reductions to satisfy accepted purchasers' Bids to buy Energy from the Day-Ahead Market; (ii) providing sufficient Ancillary Services to support Energy purchased from the Day-Ahead Market consistent with the Regulation Service Demand curve and Operating Reserve Demand Curves set forth in Rate Schedules 3 and 4 respectively of this ISO Services Tariff; (iii) committing sufficient Capacity to meet the ISO's Load forecast and provide associated Ancillary Services; and (iv) meeting Bilateral Transaction schedules submitted Day-Ahead excluding schedules of Bilateral Transactions with Trading Hubs as their POWs. The computer algorithm shall consider whether accepting Demand Reduction Bids will reduce the total Bid Production Cost.

The ISO shall compute all NYCA Interface Transfer Capabilities prior to scheduling Transmission Service Day-Ahead. The ISO shall run the SCUC utilizing the computed Transfer Capabilities, submitted Firm Point-to-Point Transmission Service requests, Load forecasts, and submitted Incremental Energy Bids, Decremental Bids and Sink Price Cap Bids.

The schedule will include commitment of sufficient Generators and/or Demand Side Resources to provide for the safe and reliable operation of the NYS Power System. SCUC will treat a Behind-the-Meter Net Generation Resources and Energy Storage Resources as already being committed and available to be scheduled. Pursuant to ISO Procedures, the ISO may schedule any Resource to run above its UOL_N up to the level of its UOL_E. In cases in which the sum of all Bilateral Schedules, excluding Bilateral Schedules for Transactions with Trading Hubs as their POWs, and all Day-Ahead Market purchases to serve Load within the NYCA in the Day-Ahead schedule is less than the ISO's Day-Ahead forecast of Load, the ISO will commit Resources in addition to the Operating Reserves it normally maintains to enable it to respond to contingencies. The purpose of these additional resources is to ensure that sufficient Capacity is available to the ISO in real-time to enable it to meet its Load forecast (including associated Ancillary Services). In considering which additional Resources to schedule to meet the ISO's Load forecast, the ISO will evaluate unscheduled Imports, and will not schedule those Transactions if its evaluation determines the cost of those Transactions would effectively exceed a Bid Price cap in the hours in which the Energy provided by those Transactions is required. In addition to all Reliability Rules, the ISO shall consider the following information when developing the SCUC schedule: (i) Load forecasts; (ii) Ancillary Service requirements as determined by the ISO given the Regulation Service Demand Curve and Operating Reserve Demand Curves referenced above; (iii) Bilateral Transaction schedules excluding Bilateral Schedules for Transactions with Trading Hubs as their POWs; (iv) price Bids and operating Constraints submitted for Generators or for Demand Side Resources; (v) price Bids for Ancillary Services; (vi) Decremental Bids and Sink Price Cap Bids for External Transactions; and (vii) Bids to purchase or sell Energy from or to the Day-Ahead Market. External Transactions with minimum run times greater than one hour will only be scheduled at the requested Bid for the full minimum run time. External Transactions with identical Bids and minimum run times greater than one hour will not be prorated. The SCUC schedule shall list the hourly injections and withdrawals for: (a) each Customer whose Bid the ISO accepts for the Dispatch Day; and (b) each Bilateral Transaction scheduled Day-Ahead excluding Bilateral Transactions with Trading Hubs as their POWs.

In the development of its SCUC schedule, the ISO may commit and de-commit Generators and Demand Side Resources, based upon any flexible Bids, including Minimum Generation Bids, Start-Up Bids, Curtailment Initiation Cost Bids, Energy, and Incremental Energy Bids and Decremental Bids received by the ISO provided however that: (a) the ISO shall commit zero megawatts of Energy for Demand Side Resources committed to provide Operating Reserves and Regulation Service; and (b) for Behind-the-Meter Net Generation Resources, the ISO will consider for dispatch only those segments of the Resource's Incremental Energy Bids above the forecasted Host Load and subject to the Injection Limit.

The ISO may disable the ISO-Managed Energy Level bid parameter that is ordinarily available to Energy Storage Resources if it determines that there is a significant risk that including the ISO-Managed Energy Level bid parameter in the SCUC evaluation could delay the completion and posting of the Day-Ahead Market beyond the 11:00 a.m. deadline specified in Section 4.2.5 of this Services Tariff. The ISO shall post a notice to its public website by 4:00 p.m. on the day before the Day-Ahead Market closes if it decides to disable the ISO-Managed Energy Level bid parameter. The ISO-Managed Energy Level bid parameter shall remain disabled until the ISO posts a notice that complies with the notice requirement specified above reinstating the bid parameter's availability.

When the ISO-Managed Energy Level bid parameter is disabled, Bids that utilized the ISO-Managed Energy Level functionality that were submitted prior to the issuance of the ISO's notice will be rejected. The ISO will inform affected Suppliers, so that the Suppliers will have the opportunity to resubmit their Day-Ahead Market Bids using Self-Managed Energy Levels prior to the deadlines specified in Section 4.2.1.1 of the Services Tariff. Bids that utilize ISO-Managed Energy Levels will continue to be rejected until the ISO reinstates the ISO-Managed Energy Level bid parameter, following notice.

The ISO may disable the ISO-Managed Energy Level bid parameter that is ordinarily available to Energy Storage Resources if it determines that there is a significant risk that including the ISO-Managed Energy Level bid parameter in the SCUC evaluation could delay the completion and posting of the Day-Ahead Market beyond the 11:00 a.m. deadline specified in Section 4.2.5 of this Services Tariff. The ISO shall post a notice to its public website by 4:00 p.m. on the day before the Day-Ahead Market closes if it decides to disable the ISO-Managed Energy Level bid parameter. The ISO-Managed Energy Level bid parameter shall remain disabled until the ISO posts a notice that complies with the notice requirement specified above reinstating the bid parameter's availability.

When the ISO-Managed Energy Level bid parameter is disabled, Bids that utilized the ISO-Managed Energy Level functionality that were submitted prior to the issuance of the ISO's notice will be rejected. The ISO will inform affected Suppliers, so that the Suppliers will have the opportunity to resubmit their Day-Ahead Market Bids using Self-Managed Energy Levels prior to the deadlines specified in Section 4.2.1.1 of the Services Tariff. Bids that utilize ISO-Managed Energy Levels will continue to be rejected until the ISO reinstates the ISO-Managed Energy Level bid parameter, following notice.

The ISO will select the least cost mix of Ancillary Services and Energy from Suppliers, Demand Side Resources, and Customers submitting Virtual Transactions bids. The ISO may substitute higher quality Ancillary Services (*i.e.*, shorter response time) for lower quality

Ancillary Services when doing so would result in an overall least bid cost solution. For example, 10-Minute Non-Synchronized Reserve may be substituted for 30-Minute Reserve if doing so would reduce the total bid cost of providing Energy and Ancillary Services.

4.2.3.1 Reliability Forecast for the Dispatch Day

At the request of a Transmission Owner to meet the reliability of its local system, the ISO may incorporate into the ISO's Security Constrained Unit Commitment constraints specified by the Transmission Owner.

A Transmission Owner may request commitment of certain Generators for a Dispatch Day if it determines that certain Generators are needed to meet the reliability of its local system. Such request shall be made before the Day-Ahead Market for that Dispatch Day has closed if the Transmission Owner knows of the need to commit certain Generators before the Day-Ahead Market close. The ISO may commit one or more Generator(s) in the Day-Ahead Market for a Dispatch Day if it determines that the Generator(s) are needed to meet NYCA reliability requirements.

A Transmission Owner may request commitment of additional Generators for a Dispatch Day following the close of the Day-Ahead Market to meet changed or local system conditions for the Dispatch Day that may cause the Day-Ahead schedules for the Dispatch Day to be inadequate to ensure the reliability of its local system. The ISO will use SRE to fulfill a Transmission Owner's request for additional units.

All Generator commitments made in the Day-Ahead Market pursuant to this Section 4.2.3.1 shall be posted on the ISO website following the close of the Day-Ahead Market, in accordance with ISO procedures. In addition, the ISO shall post on its website a non-binding, advisory notification of a request, or any modifications thereto, made pursuant to this Section

4.2.3.1 in the Day-Ahead Market by a Transmission Owner to commit a Generator that is located within a Constrained Area, as defined in Attachment H of this Services Tariff. The advisory notification shall be provided upon receipt of the request and in accordance with ISO procedures. The postings described here may be included with the operator-initiated commitment report that the ISO posts in accordance with Section 4.1.3.4 of this Services Tariff.

After the Day-Ahead schedule is published, the ISO shall evaluate any events, including, but not limited to, the loss of significant Generators or transmission facilities that may cause the Day-Ahead schedules to be inadequate to meet the Load or reliability requirements for the Dispatch Day.

In order to meet Load or reliability requirements in response to such changed conditions the ISO may: (i) commit additional Resources, beyond those committed Day-Ahead, using a SRE and considering (a) Bids submitted to the ISO that were not previously accepted but were designated by the bidder as continuing to be available; or (b) new Bids from all Suppliers, including neighboring systems; or (ii) take the following actions: (a) after providing notice, require all Resources to run above their UOL_Ns, up to the level of their UOL_Es (pursuant to ISO Procedures) and/or raise the UOL_Ns of Capacity Limited Resources and Energy Limited Resources to their UOL_E levels, or (b) cancel or reschedule transmission facility maintenance outages when possible. Actions taken by the ISO in performing supplemental commitments will not change any financial commitments that resulted from the Day-Ahead Market.

4.2.4 Reliability Forecast for the Six Days Following the Dispatch Day

In the SCUC program, system operation shall be optimized based on Bids over the Dispatch Day. However, to preserve system reliability, the ISO must ensure that there will be sufficient resources available to meet forecasted Load and reserve requirements over the seven

(7)-day period that begins with the next Dispatch Day. The ISO will perform a Supplemental Resource Evaluation ("SRE") for days two (2) through seven (7) of the commitment cycle. If it is determined that 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) is needed for reliability, the ISO shall accept a Bid from the Generator and the Generator will begin its start-up sequence. During each day of the start-up sequence, the ISO will perform an SRE to determine if long start-up time Generators will still be needed as previously forecasted. If at any time it is determined that the Generator will not be needed as previously forecasted, the ISO shall order the Generator to abort its start-up sequence.

The ISO will commit to long start-up time Generators to preserve reliability. However, the ISO will not commit resources with long start-up times to reduce the cost of meeting Loads that it expects to occur in days following the next Dispatch Day.

A Supplier that bids on behalf of a long start-up time Generator, including one that is committed and whose start is subsequently aborted by the ISO as described in this Section 4.2.4, may be eligible for a Bid Production Cost Guarantee pursuant to the provisions of Section 4.6.6 and Attachment C of this ISO Services Tariff. The costs of such a Bid Production Cost guarantee will be recovered by the ISO under Rate Schedule 1 of the ISO OATT.

The ISO shall perform the SRE as follows: (1) The ISO shall develop a forecast of daily system peak Load for days two (2) through seven (7) in this seven (7)-day period and add the appropriate reserve margin; (2) the ISO shall then forecast its available Generators for the day in question by summing the Operating Capacity for all Generators currently in operation that are available for the commitment cycle, the Operating Capacity of all other Generators capable of starting on subsequent days to be available on the day in question, and an estimate of the net

Imports from External Bilateral Transactions; (3) if the forecasted peak Load plus reserves exceeds the ISO's forecast of available Generators for the day in question, then the ISO shall commit additional Generators capable of starting prior to the day in question (*e.g.,* start-up period of two (2) days when looking at day three (3)) to assure system reliability; (4) in choosing among Generators with comparable start-up periods, the ISO shall schedule Generators to minimize Minimum Generation Bid and Start-Up Bid costs of meeting forecasted peak Load plus Ancillary Services consistent with the Reliability Rules; (5) in determining the appropriate reserve margin for days two (2) through seven (7), the ISO will supplement the normal reserve requirements to allow for forced outages of the short start-up period units (*e.g.*, gas turbines) assumed to be operating at maximum output in the unit commitment analysis for reliability.

Energy Bids are binding for day one (1) only for units in operation or with start-up periods less than one (1) day. Minimum Generation Bids for Generators with start-up periods greater than one (1) day will be binding only for units that are committed by the ISO and only for the first day in which those units could produce Energy given their start-up periods. For example, Minimum Generation Bids for a Generator with a start-up period of two (2) days would be binding only for day three (3) because, if that unit begins to start up at any time during day one (1), it would begin to produce Energy forty-eight (48) hours later on day three (3). Similarly, the Minimum Generation Bids for a Generator with a start-up period of three (3) days would be binding only for day four (4).

4.2.5 Post the Day-Ahead Schedule

By 11 a.m. on the day prior to the Dispatch Day, the ISO shall close the Day-Ahead scheduling process and post on the Bid/Post System the Day-Ahead schedule for each entity that submits a Bid or Bilateral Transaction schedule. All schedules shall be considered proprietary, with the posting only visible to the appropriate scheduling Customer and Transmission Owners subject to the applicable Code of Conduct (See Attachment F to the ISO OATT). The ISO will post on the OASIS the statewide aggregate resources (Day-Ahead Energy schedules and total operating capability forecast), Day-Ahead scheduled Load, forecast Load for each Load Zone, and the Day-Ahead LBMP prices (including the Congestion Component and the Marginal Losses Component) for each Load Zone in each hour of the upcoming Dispatch Day. The ISO shall conduct the Day-Ahead Settlement based upon the Day-Ahead schedule determined in accordance with this section and Attachment B to this Services Tariff. The ISO will provide the Transmission Owner with the Load forecast (for seven (7) days) as well as the ISO security evaluation data to enable local area reliability to be assessed.

4.2.6 Day-Ahead LBMP Market Settlements

The ISO shall calculate the Day-Ahead LBMPs for each Load Zone and at each Generator bus and Demand Reduction Bus as described in Attachment B. Each Supplier that bids a Generator into the ISO Day-Ahead Market and is scheduled in the SCUC to sell or purchase Energy in the Day-Ahead Market will be settled at the product of: (a) the Day-Ahead hourly LBMP at the applicable Generator bus; and (b) the hourly Energy schedule. Each Supplier that bids an External Transaction into the Day-Ahead LBMP Market and is scheduled in the SCUC to sell Energy into the Day-Ahead LBMP Market will be settled at the product of (a) the Day-Ahead LBMP at the applicable Proxy Generator Bus and (b) the External Transaction schedule. 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 settled at 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). In addition, each Demand Reduction Provider that bids a Demand Reduction into the Day-Ahead Market and is scheduled in the SCUC to provide Energy through Demand Reduction shall receive a Demand Reduction Incentive Payment from the ISO equal to the product of: (a) the Day-Ahead hourly LBMP at the Demand Reduction bus; and (b) the lesser of the verified actual hourly Demand Reduction or the scheduled hourly Demand Reduction (in MW). Each Customer that bids into the Day-Ahead Market, including each Customer that submits a Bid for a Virtual Transaction, and has a schedule accepted by the ISO 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. Each Supplier that bids an External Transaction into the Day-Ahead LBMP Market and is scheduled in the SCUC to buy Energy from the Day-Ahead LBMP Market will pay the product of (a) the Day-Ahead LBMP at the applicable Proxy Generator Bus and (b) the External Transaction schedule. Each Customer that submits a Virtual Transaction bid into the ISO Day-Ahead Market and has a schedule accepted by the ISO to sell Energy in a Load Zone in the Day-Ahead Market will receive a payment equal to the product of (a) the Day-Ahead hourly zonal LBMP for that Load Zone; and (b) the hourly scheduled Energy for the Customer in that Load Zone. Each Trading Hub Energy Owner who bids a Bilateral Transaction into the Day-Ahead Market with a Trading Hub as its POI and has its schedule accepted by the ISO will pay 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 MW. Each Trading Hub Energy Owner who bids a Bilateral Transaction into the Day-Ahead Market with a Trading Hub as its POW and has its schedule accepted by the

ISO 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 MW.

The ISO shall publish the Day-Ahead Settlement Load Zone LBMPs for each hour in the Dispatch Day.

4.4 Real-Time Markets and Schedules

4.4.1 Real-Time Commitment (“RTC”)

4.4.1.1 Overview

RTC will make binding unit commitment and de-commitment decisions for the periods beginning fifteen minutes (in the case of Resources that can respond in ten minutes) and thirty minutes (in the case of Resources that can respond in thirty minutes) after the scheduled posting time of each RTC run, will provide advisory commitment information for the remainder of the two and a half hour optimization period, and will produce binding schedules for External Transactions to begin at the start of each quarter hour. RTC will treat Behind-the-Meter Net Generation Resources and Energy Storage Resources as already being committed and available to be scheduled. RTC will co-optimize to solve simultaneously for all Load, Operating Reserves and Regulation Service and to minimize the total as-bid production costs over its optimization timeframe. RTC will consider SCUC’s Resource commitment for the day, load forecasts that RTC itself will produce each quarter hour, binding transmission constraints, and all Real-Time Bids and Bid parameters submitted pursuant to Section 4.4.1.2 below.

4.4.1.2 Bids and Other Requests

After the Day-Ahead schedule is published and before the close of the Real-Time Scheduling Window for each hour, Customers may submit Real-Time Bids into the Real-Time Market for real-time evaluation by providing all information required to permit real-time evaluation pursuant to ISO Procedures. If the Supplier elects to participate in the Real-Time Market, and is within a defined electrical boundary, electrically interconnected with, and routinely serves a Host Load (which Host Load does not exclusively consist of Station Power) at a single PTID, it can only participate in the Real-Time Market as a Behind-the-Meter Net

Generation Resource. If a Behind-the-Meter Net Generation Resource submits Bids into the Real-Time Market for real-time evaluation, such Bids shall provide the forecasted Host Load for each hour for which Bids are submitted.

An Energy Storage Resource shall indicate in its Real-Time Bids whether its Energy Level will be ISO- or Self-Managed. An Energy Storage Resource that elects to Self-Manage its Energy Level shall be responsible for managing its Energy Level through its Bids. An Energy Storage Resource, including an Energy Storage Resource that received a Day-Ahead Schedule, may change its Energy Level Management election for each operating hour in the Real-Time Market day.

Co-located Storage Resources can each offer all of their available capability into the Real-Time Market. RTC will account for the CSR Scheduling Limits in the schedules it determines for CSR Generators.

4.4.1.2.1 Real-Time Bids to Supply or Withdraw Energy and Supply Ancillary Services, other than External Transactions

Intermittent Power Resources that depend on wind or solar energy as their fuel submitting new or revised offers to supply Energy shall bid as ISO-Committed Flexible and shall submit a Minimum Generation Bid of zero MW and zero cost and a Start-Up Bid at zero cost.

Eligible Customers may submit new or revised Bids to supply or withdraw Energy, and to supply Operating Reserves and/or Regulation Service. Customers that submit such Bids may specify different Bid parameters in real-time than they did Day-Ahead.

Incremental Energy Bids, for portions of the Capacity of Resources that were scheduled in the Day-Ahead Market, and/or Start-Up Bids may be submitted by Suppliers bidding Resources using ISO-Committed Fixed, ISO-Committed Flexible, and Self-Committed Flexible bid modes that exceed the Incremental Energy Bids or Start-Up Bids submitted in the Day-

Ahead Market or the mitigated Day-Ahead Incremental Energy Bids or Start-Up Bids where appropriate, if not otherwise prohibited pursuant to other provisions of the tariff.

The ISO will use a Fast-Start Resource's single point Start-Up Bid if one is submitted (or the mitigated Bid, where appropriate). If a Fast-Start Resource does not submit a single point Start-Up Bid in real-time, the ISO will use the point on the Fast-Start Resource's multi-point Start-Up Bid curve (or its mitigated multi-point Start-Up Bid curve, where appropriate) that corresponds to the shortest specified down time.

Minimum Generation Bids or Regulation Service Bids for any hour in which Resources received a Day-Ahead Energy schedule or a Regulation Service schedule, as appropriate, may not exceed the Minimum Generation Bids or Regulation Service Bids, as appropriate, submitted for those Resources in the Day-Ahead Market. Provided however, a Fast-Start Resource that receives a Day-Ahead schedule may submit Minimum Generation Bids using ISO-Committed Fixed, ISO-Committed Flexible, and Self-Committed Flexible bid modes that exceed the dollar component of the Bids submitted in the Day-Ahead Market, or the dollar component of the mitigated Day-Ahead Bids where appropriate, if not otherwise prohibited pursuant to other provisions of the tariff.

Additionally, Real-Time Minimum Run Qualified Gas Turbine Customers shall not increase their previously submitted Real-Time Incremental Energy Bids, Minimum Generation Bids, or Start-Up Bids within 135 minutes of the dispatch hour. Bids to supply Energy or Ancillary Services shall be subject to the rules set forth in Section 4.2.1 of this ISO Services Tariff. For Behind-the-Meter Net Generation Resources, the ISO will consider only those segments of the Resource's Incremental Energy Bids above the forecasted Host Load and subject to the Injection Limit.

Suppliers bidding on behalf of Generators that did not receive a Day-Ahead schedule for a given hour may offer their Generators, for those hours, using the ISO-Committed Flexible, Self-Committed Flexible, Self-Committed Fixed bid mode or, with ISO approval, the ISO-Committed Fixed bid modes in real-time. For Behind-the-Meter Net Generation Resources, the ISO will consider only those segments of the Resource's Incremental Energy Bids above the forecasted Host Load and subject to the Injection Limit. Suppliers bidding on behalf of Demand Side Resources that did not receive a Day-Ahead schedule to provide Operating Reserves or Regulation Service for a given hour may offer to provide Operating Reserves or Regulation Service using the ISO-Committed Flexible bid mode for that hour in the Real-Time Market provided, however, that the Demand Side Resource shall have an Energy price Bid no lower than the Monthly Net Benefit Offer Floor. A Supplier bidding on behalf of a Generator that received a Day-Ahead schedule for a given hour may not change the bidding mode for that Generator for the Real-Time Market for that hour provided, however, that Generators that were scheduled Day-Ahead in Self-Committed Fixed mode may switch, with ISO approval, to ISO-Committed Fixed bidding mode in real-time. Generators that were scheduled Day-Ahead in ISO-Committed Fixed mode will be scheduled as Self-Committed Fixed in the Real-Time Market unless, with ISO approval, they change their bidding mode to ISO-Committed Fixed.

Co-located Storage Resources must each submit a CSR injection Scheduling Limit and a CSR withdrawal Scheduling Limit for each hour of the Real-Time Market to indicate the expected capability of the relevant facilities. An Energy Storage Resource that participates in a CSR shall not submit Real-Time Market Bids that would Self-Commit the Generator to inject or to withdraw a quantity of Energy that exceeds an applicable CSR Scheduling Limit.

A Generator with a real time physical operating problems that makes it impossible for them: (a) to operate in the bidding mode in which the Generator or Aggregation was scheduled Day-Ahead; or (b) to provide all of the Energy or Ancillary Services offered in their Bids, or (c) to achieve or comply with applicable operating parameters or other requirements, shall notify the ISO. Additionally, if the Host Load of a Behind-the-Meter Net Generation Resource is greater in real-time than was forecasted Day-Ahead such that it cannot meet its Day-Ahead schedule, it must notify the ISO.

Generators and Demand Side Resources may not submit separate Operating Reserves Availability Bids in real-time and will instead automatically be assigned a real-time Operating Reserves Availability Bid of zero for the amount of Operating Reserves they are capable of providing in light of their response rate (as determined under Rate Schedule 4).

4.4.1.2.2 Real-Time Bids Associated with Internal and External Bilateral Transactions

Customers may use Real-Time Bids to seek to modify Bilateral Transactions that were previously scheduled Day-Ahead or propose new Bilateral Transactions, including External Transactions, for economic evaluation by RTC, provided however, that Bilateral Transactions with Trading Hubs as their POWs that were previously scheduled Day-Ahead may not be modified. Bids associated with Internal Bilateral Transactions shall be subject to the rules set forth above in Section 4.2.1.7.

Except as provided in this section, External Transaction Bids may not vary over the course of an hour. Each such Bid must offer to import, export or wheel the same amount of Energy at the same price at each point in time within that hour. At Variably Scheduled Proxy Generator Buses the ISO shall permit the submission of Bids to import or export Energy that vary the amount of Energy, and vary the price, for each quarter hour evaluation period.

The ISO may vary External Transaction Schedules at Proxy Generator Buses that are authorized to schedule transactions on an intra-hour basis if the party submitting the Bid for such a Transaction elects to permit variable scheduling. The ISO may also vary External Transaction Schedules at CTS Enabled Proxy Generator Buses. External Transaction Bids submitted to import Energy from, or export Energy to Proxy Generator Buses that are authorized to schedule transactions on either an intra-hour or hourly basis shall indicate whether the ISO may vary schedules associated with those Bids within each hour. Transmission Customers scheduling External Bilateral Transactions shall also be subject to the provisions of Section 16, Attachment J of the ISO OATT.

4.4.1.2.3 Self-Commitment Requests

Self-Committed Flexible Resources must provide the ISO with schedules of their expected minimum operating points in quarter hour increments. Self-Committed Fixed Resources must provide their expected actual operating points in quarter hour increments or, with ISO approval, bid as an ISO-Committed Fixed Generator.

4.4.1.2.4 ISO-Committed Fixed

The ability to use the ISO-Committed Fixed bidding mode in the Real-Time Market shall be subject to ISO approval pursuant to procedures, which shall be published by the ISO. Generators that have exclusively used the Self-Committed Fixed or ISO-Committed Fixed bid modes in the Day-Ahead Market or that do not have the communications systems, operational control mechanisms or hardware to be able to respond to five-minute dispatch basepoints are eligible to bid using the ISO-Committed Fixed bid mode in the Real-Time Market. Real-Time Bids by Generators using the ISO-Committed Fixed bid mode in the Real-Time Market shall provide variable Energy price Bids, consisting of up to eleven monotonically increasing, constant cost incremental Energy steps, Minimum Generation Bids, hourly Start-Up Bids and other information pursuant to ISO Procedures.

RTC shall schedule ISO-Committed Fixed Generators.

4.4.1.3 External Transaction Scheduling

RTC15 will schedule External Transactions on an hourly basis as part of its development of a co-optimized least-bid cost Real-Time Commitment. For External Transactions that are scheduled on a 15 minute basis, the amount of Energy scheduled to be imported, exported or wheeled in association with that External Transaction may change on the quarter hour. All RTC runs will schedule intra-hour External Transactions on a 15 minute basis at Variably Scheduled Proxy Generator Buses. RTC will alert the ISO when it appears that scheduled External Transactions need to be reduced for reliability reasons but will not automatically Curtail them. Curtailment decisions will be made by the ISO, guided by the information that RTC provides, pursuant to the rules established by Attachment B of this ISO Services Tariff and the ISO Procedures. External Bilateral Transaction schedules are also governed by the provisions of Section 16, Attachment J of the OATT.

4.4.1.4 Posting Commitment/De-Commitment and External Transaction Scheduling Decisions

Except as specifically noted in Section 4.4.2, 4.4.3 and 4.4.4 of this ISO Services Tariff, RTC will make all Resource commitment and de-commitment decisions. RTC will make all economic commitment/de-commitment decisions based upon available offers assuming Suppliers internal to the NYCA have a minimum run time of at least 15 minutes, but not longer than one hour; provided however, Real-Time Minimum Run Qualified Gas Turbines shall be assumed to have a two-hour minimum run time. For Behind-the-Meter Net Generation

Resources, RTC will consider only those segments of the Resource's Incremental Energy Bids above the forecasted Host Load and subject to the Injection Limit.

RTC will produce advisory commitment information and advisory real-time prices. RTC will make decisions and post information in a series of fifteen-minute "runs" which are described below.

RTC_{15} will begin at the start of the first hour of the RTC co-optimization period and will post its commitment, de-commitment, and External Transaction scheduling decisions no later than fifteen minutes after the start of that hour. During the RTC_{15} run, RTC will:

(i) Commit Resources with 10-minute start-up times that should be synchronized by the time that the results of the next RTC run are posted so that they will be synchronized and running at their scheduled dispatch levels by that time;

(ii) Commit Resources with 30-minute start-up times that should be synchronized by the time that the results of the RTC run following the next RTC run are posted so that they will be synchronized and running at their scheduled dispatch levels by that time;

(iii) De-commit Resources that should be disconnected from the network by the time that the results of the next RTC run are posted so that they will be disconnected by that time;

(iv) Issue advisory commitment and de-commitment guidance for periods more than thirty minutes in the future and advisory dispatch information;

(v) Schedule economic hourly External Transactions for the next hour;

(vi) Schedule economic 15 minute External Transactions, for the quarter hour for which the results of the next RTC run are posted, at Variably Scheduled Proxy Generator Buses other than a CTS Enabled Proxy Generator Bus;

(vii) Schedule economic 15 minute External Transactions, for the quarter hour for which the results of the next RTC run are posted, at a CTS Enabled Proxy Generator Bus; and

(viii) Schedule ISO-Committed Fixed Resources.

All subsequent RTC runs in the hour, *i.e.*, RTC_{30}, RTC_{45}, and RTC_{00} will begin executing at fifteen minutes before their designated posting times (for example, RTC_{30} will begin in the fifteenth minute of the hour), and will take the following steps:

(i) Commit Resources with 10-minute start-up times that should be synchronized by the time that the results of the next RTC run are posted so that they will be synchronized and running at that time;

(ii) Commit Resources with 30-minute start-up times that should be synchronized by the time that the results of the RTC run following the next RTC run are posted so that they will be synchronized and running at that time;

(iii) De-commit Resources that should be disconnected from the network by the time that the results of the next RTC run are posted so that they will be disconnected at that time;

(iv) Issue advisory commitment, de-commitment, and dispatching guidance for the period from thirty minutes in the future until the end of the RTC co-optimization period;

(v) Either reaffirm that the External Transactions scheduled by previous RTC runs should continue to flow in the next hour, or inform the ISO that External Transactions may need to be reduced;

(vi) Schedule economic 15 minute External Transactions, for the quarter hour for which the results of the next RTC run are posted, at Variably Scheduled Proxy Generator Buses other than a CTS Enabled Proxy Generator Bus;

(vii) Schedule economic 15 minute External Transactions, for the quarter hour for which the results of the next RTC run are posted, at a CTS Enabled Proxy Generator Bus; and

(viii) Schedule ISO-Committed Fixed Resources.

4.4.1.5 External Transaction Settlements

Settlements for External Transactions in the LBMP Market are described in Sections 4.2.6 and 4.5 of this ISO Services Tariff. Settlements for External Bilateral Transactions are also described in Section 16, Attachment J and Rate Schedules 7 and 8 of the OATT.

The calculation of Real-Time LBMPs at Proxy Generator Buses and CTS Enabled Interfaces is described in Section 17, Attachment B to this ISO Services Tariff.

4.4.2 Real-Time Dispatch

4.4.2.1 Overview

The Real-Time Dispatch will make dispatching decisions, send Base Point Signals to Internal Generators and Demand Side Resources, produce schedules for intra-hour External Transactions at Dynamically Scheduled Proxy Generator Buses, calculate Real-Time Market clearing prices for Energy, Operating Reserves, and Real-Time Market Prices for Regulation Service, and establish real-time schedules for those products on a five-minute basis, starting at the beginning of each hour. The Real-Time Dispatch will not make commitment decisions and will not consider start-up costs in any of its dispatching or pricing decisions, except as specifically provided in Section 4.4.2.4 below. Real-Time Dispatch will review each Energy Storage Resource's Beginning Energy Level in each interval. Real-Time Dispatch will attempt to prevent dispatching a Self-Managed Energy Storage Resource in a manner that would be infeasible based on its Beginning Energy Level. Instead, Real-Time dispatch will consider an Energy Storage Resource's Beginning Energy Level in developing a schedule for the binding interval. An Energy Storage Resource's Beginning Energy Level will be used to ensure that Operating Reserves scheduled from the Resource can be sustained for one hour if the Operating Reserves are converted to Energy. The Real-Time Dispatch will account for the CSR Scheduling Limits in the schedules and dispatch instructions it issues to CSR Generators.

Each Real-Time Dispatch run will co-optimize to solve simultaneously for Load, Operating Reserves, and Regulation Service and to minimize the total cost of production over its bid optimization horizon (which may be fifty, fifty-five, or sixty minutes long depending on where the run falls in the hour.) In addition to producing a binding schedule for the next five minutes, each Real-Time Dispatch run will produce advisory schedules for the remaining four time steps of its bid-optimization horizon (which may be five, ten, or fifteen minutes long depending on where the run falls in the hour). An advisory schedule may become binding in the absence of a subsequent Real-Time Dispatch run. RTD will use the most recent system information and the same set of Bids and constraints that are considered by RTC.

4.4.2.2 External Transaction Scheduling

All RTD runs will schedule External Transactions on a 5 minute basis at Dynamically Scheduled Proxy Generator Buses. For External Transactions that are scheduled on a 5 minute basis, the amount of Energy scheduled to be imported, exported or wheeled in association with that External Transaction may change every 5 minutes. External Bilateral Transaction Schedules are also governed by the provisions of Attachment J of the OATT.

4.4.2.3 Calculating Real-Time Market LBMPs and Advisory Prices

RTD shall calculate *ex ante* Real-Time LBMPs at each Generator bus, and for each Load Zone in each RTD cycle, in accordance with the procedures set forth in Attachment B to this ISO Services Tariff. RTD will also calculate and post advisory Real-Time LBMPs for the next four quarter hours in accordance with the procedures set forth in Attachment B.

4.4.2.4 Real-Time Pricing Rules for Scheduling Ten Minute Resources

RTD may commit and dispatch, for pricing purposes, Resources capable of starting and meeting Minimum Generation Levels within ten minutes ("eligible Resources") when necessary to meet load. Eligible Resources committed and dispatched by RTD for pricing purposes may be physically started through normal ISO operating processes. In the RTD cycle in which RTD commits and dispatches an eligible Resource, RTD will consider the Resource's start-up and incremental energy costs and will assume the Resource has a zero downward response rate for purposes of calculating *ex ante* Real-Time LBMPs pursuant to Section 17, Attachment B to this ISO Services Tariff.

4.4.2.5 Converting to Demand Reduction, Special Case Resource Capacity scheduled as Operating Reserves, Regulation or Energy in the Real-Time Market

The ISO shall convert to Demand Reductions, in hours in which the ISO requests that Responsible Interface Parties notify their Special Case Resources to reduce their demand pursuant to ISO Procedures, any Operating Reserves, Regulation Service or Energy scheduled in the Day-Ahead Market from Demand Side Resources that are also providing Special Case Resource Capacity. The ISO shall settle the Demand Reduction provided by that portion of the Special Case Resource Capacity that was scheduled Day-Ahead as Operating Reserves, Regulation Service or Energy as being provided by a Supplier of Operating Reserves, Regulation Service or Energy as appropriate. The ISO shall settle any remaining Demand Reductions provided beyond Capacity that was scheduled Day-Ahead as Ancillary Services or Energy as being provided by a Special Case Resource, provided such Demand Reduction is otherwise payable as a reduction by a Special Case Resource.

Operating Reserves or Regulation Service scheduled Day-Ahead and converted to Energy in real time pursuant to this Section 4.4.2.4, will be eligible for a Day-Ahead Margin Assurance Payment, pursuant to Attachment J of this ISO Services Tariff.

Special Case Resource Capacity that has been scheduled in the Day-Ahead Market to provide Operating Reserves, Regulation Service or Energy and that has been instructed as a Special Case Resource to reduce demand shall be considered, for the purpose of determining a Scarcity Reserve Requirement pursuant to Rate Schedule 4 of this ISO Services Tariff, to be a Special Case Resource.

The ISO shall not accept offers of Operating Reserves or Regulation Service in the Real-Time Market from Demand Side Resources that are also providing Special Case Resource Capacity for any hour in which the ISO has requested Special Case Resources to reduce demand.

4.4.2.6 Converting to Demand Reduction Curtailment Services Provider Capacity scheduled as Operating Reserves, Regulation or Energy in the Real-Time Market

The ISO shall convert to Demand Reductions, in hours in which the ISO requests Demand Reductions from the Emergency Demand Response Program pursuant to ISO

Procedures, any Operating Reserves, Regulation Service or Energy scheduled in the Day-Ahead Market by Demand Side Resources that are also providing Curtailment Services Provider Capacity. The ISO shall settle the Demand Reduction provided by that portion of the Curtailment Services Provider Capacity that was scheduled Day-Ahead as Operating Reserves, Regulation Service or Energy as being provided by a Supplier of Operating Reserves, Regulation Service or Energy as appropriate. The ISO shall settle Demand Reductions provided beyond Capacity that was scheduled Day-Ahead as ancillary services or Energy as being provided by a Curtailment Services Provider.

Operating Reserves or Regulation Service scheduled Day-Ahead and converted to Energy in real time pursuant to this Section 4.4.2.5, will be eligible for a Day-Ahead Margin Assurance Payment, pursuant to Attachment J of this ISO Services Tariff.

Curtailment Services Provider Capacity that has been scheduled in the Day-Ahead Market as Operating Reserves, Regulation Service or Energy and that has been instructed to reduce demand shall be considered, for the purpose of determining a Scarcity Reserve Requirement pursuant to Rate Schedule 4 of this ISO Services Tariff, to be a Emergency Demand Response Program Resource.

The ISO shall not accept offers of Operating Reserves and Regulation Service in the Real-Time Market from Demand Side Resources that are also providing Curtailment Services Provider Capacity for any hour in which the ISO has requested participants in the Emergency Demand Response Program pursuant to ISO Procedures to reduce demand.

4.4.2.7 Post the Real-Time Schedule

Subsequent to the close of the Real-Time Scheduling Window, the ISO shall post the real-time schedule for each entity that submits a Bid or Bilateral Transaction schedule. All schedules shall be considered proprietary, with the posting only visible to the appropriate scheduling Customer, Transmission Customer and Transmission Owners subject to the applicable Code of Conduct (See Attachment F to the ISO OATT). The ISO will post on the OASIS the real-time Load for each Load Zone, and the Real-Time LBMP prices (including the Congestion Component and the Marginal Losses Component) for each Load Zone for each hour of the Dispatch Day. The ISO shall conduct the real-time settlement based upon the real-time schedule determined in accordance with this Section.

4.4.3 Real-Time Dispatch - Corrective Action Mode

When the ISO needs to respond to system conditions that were not anticipated by RTC or the regular Real-Time Dispatch, *e.g.*, the unexpected loss of a major Generator or Transmission line, it will activate the specialized RTD-CAM program. RTD-CAM runs will be nominally either five or ten minutes long, as is described below. Unlike the Real-Time Dispatch, RTD-CAM will have the ability to commit certain Resources, and schedule intra-hour External Transactions at Dynamically Scheduled Proxy Generator Buses. When RTD-CAM is activated, the ISO will have discretion to implement various measures to restore normal operating conditions. These RTD-CAM measures are described below.

The ISO shall have discretion to determine which specific RTD-CAM mode should be activated in particular situations. In addition, RTD-CAM may require Resources to run above their UOL_Ns, up to the level of their UOL_Es as is described in the ISO Procedures. Self-Committed Fixed Resources will not be expected to move in response to RTD-CAM Base Point Signals except when a maximum generation pickup is activated.

Except as expressly noted in this section, RTD-CAM will dispatch the system in the same manner as the normal Real-Time Dispatch.

4.4.3.1 RTD-CAM Modes

4.4.3.1.1 Reserve Pickup

The ISO will enter this RTD-CAM mode when necessary to re-establish schedules when large area control errors occur. When in this mode, RTD-CAM will send 10-minute Base Point Signals and produce schedules for the next ten minutes. RTD-CAM may also commit, or if necessary de-commit, Resources capable of starting or stopping within 10-minutes. The ISO will continue to optimize for Energy and Operating Reserves, will recognize locational Operating Reserve requirements and Scarcity Reserve Requirements, but will set all Regulation Service schedules to zero. If Resources are committed or de-committed in this RTD-CAM mode the schedules for them will be passed to RTC and the Real-Time Dispatch for their next execution.

Resources that are eligible to provide Operating Reserves and that are available to the ISO for dispatch in real-time are required to be able to meet the energy sustainability requirements set forth in applicable NERC, NPCC and/or NYSRC reliability requirements. When the ISO enters a reserve pickup RTD-CAM mode it will determine sustainable Energy schedules for Energy Storage Resources that are eligible to provide Operating Reserves and that are available to the ISO for dispatch based on their telemetered state of charge.

The ISO will have discretion to classify a reserve pickup as a "large event" or a "small event." In a small event the ISO will have discretion to reduce Base Point Signals in order to reduce transmission line loadings. The ISO will not ordinarily have this discretion in large events, except that it may determine Energy schedules that satisfy Operating Reserve energy sustainability requirements for Energy Storage Resources. The distinction also has significance with respect to a Supplier's eligibility to receive Bid Production Cost guarantee payment in accordance with Section 4.6.6 and Attachment C of this ISO Services Tariff.

4.4.3.1.2 Maximum Generation Pickup

The ISO will enter this RTD-CAM mode when an Emergency makes it necessary to maximize Energy production in one or more location(s), i.e., Long Island, New York City, Southeastern New York, East of Central East and/or NYCA-wide. RTD-CAM will produce schedules directing all Generators located in a targeted location to increase production at their emergency response rate up to their UOL_E level and to stay at that level until instructed otherwise. Security constraints will be obeyed to the extent possible. The ISO will continue to optimize for Energy and Operating Reserves, will recognize locational Operating Reserve requirements and Scarcity Reserve Requirements, but will set all Regulation Service schedules to zero.

4.4.3.1.3 Base Points ASAP -- No Commitments

The ISO will enter this RTD-CAM mode when changed circumstances make it necessary to issue an updated set of Base Point Signals. Examples of changed circumstances that could necessitate taking this step include correcting line, contingency, or transfer overloads and/or voltage problems caused by unexpected system events. When operating in this mode, RTD-CAM will produce schedules and Base Point Signals for the next five minutes but will only redispatch Generators that are capable of responding within five minutes. RTD-CAM will not commit or de-commit Resources in this mode.

4.4.3.1.4 Base Points ASAP -- Commit As Needed

This operating mode is identical to Base Points ASAP – No Commitments, except that it also allows the ISO to commit Generators that are capable of starting within 10 minutes when doing so is necessary to respond to changed system conditions.

4.4.3.1.5 Re-Sequencing Mode

When the ISO is ready to de-activate RTD-CAM, it will often need to transition back to normal Real-Time Dispatch operation. In this mode, RTD-CAM will calculate normal five-minute Base Point Signals and establish five minute schedules. Unlike the normal RTD-Dispatch, however, RTD-CAM will only look ahead 10-minutes. RTD-CAM re-sequencing will terminate as soon as the normal Real-Time Dispatch software is reactivated and is ready to produce Base Point signals for its entire optimization period.

4.4.3.2 Calculating Real-Time LBMPs

When RTD-CAM is activated, RTD shall calculate *ex ante* Real-Time LBMPs at each Generator bus, and for each Load Zone in accordance with the procedures set forth in Section 17, Attachment B of this ISO Services Tariff.

4.4.4 Identifying the Pricing and Scheduling Rules That Apply to External Transactions

LBMPs will be determined and External Transactions will be scheduled at external Proxy Generator Buses consistent with the table below.

Proxy Generator Bus	PTID	Scheduled Line	Designated Scheduled Line	Non-Competitive	CTS Enabled Proxy Generator Bus: Requires CTS Bids	CTS Enabled Proxy Generator Bus: Permits CTS Bids	Scheduling Frequencies: Hourly Scheduled	Scheduling Frequencies: Variably Scheduled	Scheduling Frequencies: Dynamically Scheduled (Not Presently Available)
Hydro Quebec									
HQ_GEN_IMPORT	323601			✓			✓	✓	
HQ_LOAD_EXPORT	355639			✓			✓	✓	
HQ_GEN_CEDARS_PROXY	323590	Dennison Scheduled Line		✓			✓		
HQ_LOAD_CEDARS_PROXY	355586	Dennison Scheduled Line		✓			✓		
HQ_GEN_WHEEL	23651			✓			✓		
HQ_LOAD_WHEEL	55856			✓			✓		
PJM									
PJM_GEN_KEYSTONE	24065					✓	✓* (See Notes)	✓	
PJM_LOAD_KEYSTONE	55857					✓	✓* (See Notes)	✓	
PJM_GEN_NEPTUNE_PROXY	323594	Neptune Scheduled Line	✓			✓	✓* (See Notes)	✓	
PJM_LOAD_NEPTUNE_PROXY	355615	Neptune Scheduled Line	✓			✓	✓* (See Notes)	✓	
PJM_GEN_VFT_PROXY	323633	Linden VFT Scheduled Line	✓			✓	✓* (See Notes)	✓	
PJM_LOAD_VFT_PROXY	355723	Linden VFT Scheduled Line	✓			✓	✓* (See Notes)	✓	
PJM_HTP_GEN	323702	HTP Scheduled Line	✓			✓	✓* (See Notes)	✓	

Proxy Generator Bus	PTID	Scheduled Line	Designated Scheduled Line	Non-Competitive	CTS Enabled Proxy Generator Bus		Scheduling Frequencies		
					Requires CTS Bids	Permits CTS Bids	Hourly Scheduled	Variably Scheduled	Dynamically Scheduled (Not Presently Available)
HUDSONTP_345KV_HTP_LOAD	355839	HTP Scheduled Line	✓			✓	✓* (See Notes)	✓	
ISO New England									
N.E._GEN_SANDY_POND	24062				✓		✓** (See Notes)	✓	
NE_LOAD_SANDY_PD	55858				✓		✓** (See Notes)	✓	
NPX_GEN_CSC	323557	Cross Sound Scheduled Line	✓				✓		
NPX_LOAD_CSC	355535	Cross Sound Scheduled Line	✓				✓		
NPX_GEN_1385_PROXY	323591	Northport Norwalk Scheduled Line					✓		
NPX_LOAD_1385_PROXY	355589	Northport Norwalk Scheduled Line					✓		
Ontario									
OH_GEN_PROXY	24063						✓		
OH_LOAD_PROXY	55859						✓		

Notes:

* At specifically identified Proxy Generator Buses (“* See Notes”), only Wheels Through (the NYCA) are scheduled on an hourly basis.

** At specifically identified Proxy Generator Buses (“** See Notes”), only wheels through the NYCA or a neighboring Control Area are scheduled on an hourly basis.

Pricing rules for Proxy Generator Buses are set forth in Section 17 of the Services Tariff.

The ISO may offer a more frequent scheduling option at a Proxy Generator Bus identified on the table. The ISO shall inform its Market Participants of the availability of such an option by providing notice at least two weeks in advance of the implementation of any such change. At the same time, the ISO shall update the above table to reflect the change in scheduling options by submitting a compliance filing in FERC Docket No. ER11-2547. Unless FERC acts on the ISO's compliance filing, the ISO shall effectuate the change in scheduling capability on the date it proposed in its compliance filing. The addition of new Proxy Generator Buses to the table, or changing the pricing rules that apply at a Proxy Generator Bus, may not be accomplished by submitting a compliance filing in Docket No. ER11-2547. The ISO may revert to establishing hourly Import and Export schedules using all available External Transaction Bids at a Proxy Generator Bus that is identified as a Dynamically or Variably Scheduled Proxy Generator Bus when the ISO or a neighboring Balancing Authority is not able to implement schedules as expected, or when necessary to ensure or preserve system reliability. When it reverts to hourly Import and Export schedules at a Dynamically or Variably Scheduled Proxy Generator Bus, the ISO shall apply the pricing rules for a corresponding Proxy Generator Bus that is not Dynamically Scheduled or Variably Scheduled. The ISO may cease evaluating CTS Interface Bids at CTS Enabled Proxy Generator Buses when the ISO or a neighboring Balancing Authority is not able to implement schedules as expected, or when necessary to ensure or preserve system reliability.

5.12 Requirements Applicable to Installed Capacity Suppliers

5.12.1 Installed Capacity Supplier Qualification Requirements

In order to qualify as an Installed Capacity Supplier, Generators and controllable transmission projects electrically located in the NYCA, and transmission projects with associated incremental transfer capability, must have obtained Capacity Resource Interconnection Service ("CRIS") pursuant to the applicable provisions of Attachment S to the ISO OATT and have entered service: controllable transmission projects must also have obtained Unforced Capacity Deliverability Rights and transmission projects with associated incremental transfer capability must also have obtained External-to-ROS Deliverability Rights. Generators that are Co-located Storage Resources must each, independently, obtain CRIS in order to qualify as Installed Capacity Suppliers. Even if a Generator has otherwise satisfied the requirements to participate in the ISO's Installed Capacity market, a Generator in Inactive Reserves, an ICAP Ineligible Forced Outage, a Mothball Outage, or that is Retired is ineligible to participate in the ISO's Installed Capacity market. A Generator that elects to participate in the ICAP Market, and is within a defined electrical boundary, electrically interconnected with, and routinely serves a Host Load (which Host Load does not consist solely of Station Power) at a single PTID can only participate in the Installed Capacity market as a Behind-the-Meter Net Generation Resource. Generators that are Co-located Storage Resources must each, independently, comply with all applicable market rules contained in this Services Tariff Section 5.12 as an Energy Storage Resource or as an Intermittent Power Resource, as appropriate.

In addition, to qualify as an Installed Capacity Supplier in the NYCA, Energy Limited Resources, Generators, Installed Capacity Marketers, Intermittent Power Resources, Behind-the-Meter Net Generation Resources, Limited Control Run-of-River Hydro Resources and System

Resources rated 1 MW or greater, other than External System Resources and Control Area System Resources which have agreed to certain Curtailment conditions as set forth in the third to last paragraph of Section 5.12.1 below, Responsible Interface Parties, existing municipally-owned generation, Energy Limited Resources, and Intermittent Power Resources, to the extent those entities are subject to the requirements of Section 5.12.11 of this Tariff, and Energy Storage Resources with a nameplate capacity rating that allows a minimum injection to the NYS Transmission System or distribution system of 0.1 MW or greater shall:

5.12.1.1 provide information reasonably requested by the ISO including the name and location of Generators, and System Resources;

5.12.1.2 in accordance with the ISO Procedures, perform DMNC or DMGC tests and submit the results to the ISO, or provide to the ISO appropriate historical production data;

5.12.1.3 abide by the ISO Generator maintenance coordination procedures;

5.12.1.4 provide the expected return date from any outages (including partial outages) to the ISO;

5.12.1.5 in accordance with the ISO Procedures,

5.12.1.5.1 provide documentation demonstrating that it will not use the same Unforced Capacity for more than one (1) buyer at the same time, and

5.12.1.5.2 in the event that the Installed Capacity Supplier supplies more Unforced Capacity than it is qualified to supply in any specific month (*i.e.*, is short on Capacity), documentation that it has procured sufficient Unforced Capacity to cover this shortfall.

5.12.1.6 except for Installed Capacity Marketers and Intermittent Power Resources that depend upon wind or solar as their fuel, Bid into the Day-Ahead Market, unless the Energy Limited Resource, Generator, Limited Control Run-of-River Hydro Resource or System Resource is unable to do so due to an outage as defined in the ISO Procedures or due to temperature related de-ratings. Generators may also enter into the MIS an upper operating limit that would define the operating limit under normal system conditions. The circumstances under which the ISO will direct a Generator to exceed its upper operating limit are described in the ISO Procedures;

5.12.1.6.1 Co-located Storage Resources must each submit a CSR injection Scheduling Limit and a CSR withdrawal Scheduling Limit for each hour of the Day-Ahead Market consistent with Section 5.12.7.1 below;

5.12.1.7 provide Operating Data in accordance with Section 5.12.5 of this Tariff;

5.12.1.8 provide notice to the ISO of any proposed transfers of deliverability rights to be carried out pursuant to Sections 25.9.4 - 25.9.6 of Attachment S to the ISO OATT, on the Class Year Start Date if a request to transfer CRIS at a different location, and upon the submission of the request if it is a request to transfer CRIS at the same location.

5.12.1.9 comply with the ISO Procedures;

5.12.1.10 when the ISO issues a Supplemental Resource Evaluation request (an SRE), NYCA Resources must Bid into the in-day market unless (and only to the extent) the entity has a bid pending in the Real-Time Market when the SRE request is made or is unable to bid in response to the SRE request due to an outage as defined in the ISO Procedures, or due to other operational issues, or due to temperature related deratings.

If an External Installed Capacity Supplier is a Generator, or if an External Generator is associated with an Unforced Capacity sale using UDRs or EDRs, then except to the extent such a Generator is unable to Bid in response to the SRE request due to an outage as defined in the ISO Procedures, due to physical operating limitations affecting the Generator, or due to other operational issues that are outside the Installed Capacity Supplier's control, as determined by the ISO, it must take all of the following actions for each hour of an SRE request (a) Bid an Import to the NYCA in a MW quantity equal to the lesser of (i) the ICAP equivalent of the UCAP sold, or (ii) the maximum MW the Generator is able to produce, at the approved Proxy Generator Bus, at the applicable minimum Bid Price, and (b) ensure that the External Generator is operating and is available to provide all of the MW that were Bid to be imported into the NYCA, up to the ICAP equivalent of the UCAP sold, for the entire duration of the SRE request, and (c) obtain all reservations and transmission service necessary to deliver all of the MW that were Bid to be imported into the NYCA or to a Locality from the Generator, up to the ICAP equivalent of the UCAP sold from the External Generator, at the approved Proxy Generator Bus.

If the External Installed Capacity Supplier that is a Generator, or the External Generator associated with an Unforced Capacity sale using UDRs or EDRs, is not able to Import the quantity of Energy equal to the ICAP equivalent of the UCAP sold from the Generator or EDR to the NYCA, or if a UDR to the

Locality, for every hour of an SRE request then, except to the extent already addressed by a declared outage, the Generator shall provide to the ISO an explanation of the reasons for its failure or inability to perform, including evidence demonstrating any physical operating limitations or other operational issues that prevented the Generator from Importing the quantity of Energy equal to the ICAP equivalent of the UCAP sold from the Generator to the NYCA. To the extent the ISO determines that the information and supporting evidence provided demonstrates that the failure or inability to deliver occurred for reasons outside the control of the External Installed Capacity Supplier or the External Generator associated with an Unforced Capacity sale using UDRs or EDRs, then the deficiency charge set forth in Section 5.12.12.2 below that applies solely to violations of this Section 5.12.1.10, shall not be assessed.

If an External Installed Capacity Supplier is a Control Area System Resource then, except to the extent it is unable to Bid in response to the SRE request due to an outage as defined in the ISO Procedures or due to operational issues that are outside the Installed Capacity Supplier's control, it must take all of the following actions for each hour of an SRE request (x) Bid an Import in a MW quantity equal to the ICAP equivalent of the UCAP sold, at the approved Proxy Generator Bus, at the applicable minimum Bid Price, and (y) obtain all reservations and transmission service necessary to deliver the ICAP equivalent of the UCAP sold from the Control Area System Resource to the NYCA at the approved Proxy Generator Bus.

If the External Installed Capacity Supplier that is a Control Area System Resource is not able to Import the quantity of Energy equal to the ICAP equivalent of the UCAP sold from the Control Area System Resource to the NYCA for every hour of an SRE request then, except to the extent already addressed by a declared outage, the External Installed Capacity Supplier shall provide to the ISO an explanation of the reasons for its failure or inability to perform, including evidence demonstrating any operational issues that prevented the External ICAP Supplier from Importing the quantity of Energy equal to the ICAP equivalent of the UCAP sold from the Control Area System Resource to the NYCA. To the extent the ISO determines that the information and supporting evidence provided demonstrates that the failure or inability to deliver occurred for reasons outside the External Installed Capacity Supplier's control, then the deficiency charge set forth in Section 5.12.12.2 below that applies solely to violations of this Section 5.12.1.10, shall not be assessed. A Control Area System Resource must demonstrate that transmission outage(s) prevented delivery of all available Resources in order for the ISO to determine that the Control Area System Resource's failure to Import the quantity of Energy equal to the ICAP equivalent of the UCAP sold occurred for a reason that was outside the External Installed Capacity Supplier's control.

When an External Installed Capacity Supplier that is responding to an ISO SRE request Bids its Import at a Non-Competitive Proxy Generator Bus, its obligation to Bid an Import at the applicable minimum Bid Price includes the obligation to ensure that neither the External Installed Capacity Supplier nor any of its Affiliates are offering other Imports at an equivalent or greater economic priority at the Non-Competitive Proxy Generator Bus.

5.12.1.11 Installed Capacity Suppliers located East of Central-East shall Bid in the Day-Ahead and Real-Time Markets all Capacity available for supplying 10-Minute Non-Synchronized Reserve (unless the Generator is unable to meet its commitment because of an outage as defined in the ISO Procedures), except for the Generators described in Subsections 5.12.1.11.1, 5.12.1.11.2 and 5.12.1.11.3 below;

5.12.1.11.1 Generators providing Energy under contracts executed and effective on or before November 18, 1999 (including PURPA contracts) in which the power purchasers do 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;

5.12.1.11.2 Existing topping turbine Generators and extraction turbine Generators producing 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 Generators used in replacing or repowering steam supplies from such units (in accordance with good engineering and economic design) that cannot follow schedules, up to a maximum total of 533 MW of such units; and

5.12.1.11.3 Units that have demonstrated to the ISO that they are subject to environmental, contractual or other legal or physical requirements that would otherwise preclude them from providing 10-Minute NSR.

5.12.1.12 A Resource that was determined by the ISO to be qualified as a Behind-the-Meter Net Generation Resource and for which Net Unforced Capacity was calculated by the ISO for a Capability Year can annually, by written notice received by the NYISO prior to August 1, elect not to participate in the ISO Administered Markets as a Behind-the-Meter Net Generation Resource. Such notice shall be in accordance with ISO Procedures. A Resource that makes such an election cannot participate as a Behind-the-Meter Net Generation Resource for the entire Capability Year for which it made the election, but can, however, prior to August 1 of any subsequent Capability Year, provide all required information in order to seek to re-qualify as a Behind-the-Meter Net Generation Resource.

5.12.1.13 An Energy Storage Resource may de-rate its maximum capability in order to meet the applicable Services Tariff Section 5.12.14 run-time requirement. ESRs electing to de-rate their maximum capability shall perform a DMNC test at an output level consistent with its de-rated capability in accordance with Services Tariff Section 5.12.14 and ISO Procedures (*see*, Installed Capacity Manual § 4).

5.12.1.14 Energy Limited Resources, and Energy Storage Resources must elect an Energy Duration Limitation that corresponds to a Duration Adjustment Factor, as described in Section 5.12.14 below, and validate the Energy Duration Limitation pursuant to Section 5.12.1.2 above. An Installed Capacity Supplier may elect any Energy Duration Limitation that it can demonstrate pursuant to Section 5.12.1.2.

The ISO shall inform each potential Installed Capacity Supplier that the ISO must receive and approve DMNC or DMGC data, as applicable of its approved DMNC or DMGC ratings for the Summer Capability Period and the Winter Capability Period in accordance with the ISO Procedures.

Requirements to qualify as Installed Capacity Suppliers for External System Resources and Control Area System Resources located in External Control Areas that have agreed not to Curtail the Energy associated with such Installed Capacity or to afford it the same Curtailment priority that it affords its own Control Area Load shall be established in the ISO Procedures.

External Installed Capacity not associated with UDRs, including capacity associated with External CRIS Rights, EDRs, Grandfathered External Installed Capacity Agreements listed in Attachment E of the ISO Installed Capacity Manual, the Existing Transmission Capacity for Native Load listed for New York State Electric & Gas Corporation in Table 3 of Attachment L to the ISO OATT, Import Rights, and External System Resources, is only qualified to satisfy a NYCA Minimum Unforced Capacity Requirement and is not eligible to satisfy a Locational Minimum Installed Capacity Requirement.

Not later than 30 days prior to each ICAP Spot Market Auction, each Market Participant that may make offers to sell Unforced Capacity in such auction shall submit information to the ISO, in accordance with ISO Procedures and in the format specified by the ISO that identifies each Affiliated Entity, as that term is defined in Section 23.2.1 of Attachment H of the Services Tariff, of the Market Party or with which the Market Party is an Affiliated Entity. The names of entities that are Affiliated Entities shall not be treated as Confidential Information, but such treatment may be requested for the existence of an Affiliated Entity relationship. The information submitted to the ISO shall identify the nature of the Affiliated Entity relationship by the applicable category specified in the definition of "Affiliated Entity" in Section 23.2.1 of Attachment H of the Services Tariff.

5.12.2 Additional Provisions Applicable to External Installed Capacity Suppliers

Terms in this Section 5.12.2 not defined in the Services Tariff have the meaning set forth in the OATT.

5.12.2.1 Provisions Addressing the Applicable External Control Area

External Generators, External System Resources, and Control Area System Resources qualify as Installed Capacity Suppliers if they demonstrate to the satisfaction of the NYISO that the Installed Capacity Equivalent of their Unforced Capacity is deliverable to the NYCA; in the case of an entity using a UDR to meet a Locational Minimum Installed Capacity Requirement, to the NYCA interface associated with that UDR transmission facility and will not be recalled or curtailed by an External Control Area to satisfy its own Control Area Loads; in the case of an EDR, to the NYCA interface over which it creates increased transfer capability; and in the case of Control Area System Resources, if they demonstrate that the External Control Area will afford the NYCA Load the same curtailment priority that they afford their own Control Area Native Load Customers. The amount of Unforced Capacity that may be supplied by such entities qualifying pursuant to the alternative criteria may be reduced by the ISO, pursuant to ISO Procedures, to reflect the possibility of curtailment. External Installed Capacity associated with Import Rights, EDRs or UDRs is subject to the same deliverability requirements applied to Internal Installed Capacity Suppliers associated with UDRs.

5.12.2.2 Additional Provisions Addressing Internal Deliverability and Import Rights

In addition to the provisions contained in Section 5.12.2.1 above, External Installed Capacity not associated with UDRs, EDRs, or External CRIS Rights will be subject to the deliverability test in Section 25.7.8 and 25.7.9 of Attachment S to the ISO OATT. The deliverability of External Installed Capacity not associated with UDRs, EDRs, or External CRIS Rights will be evaluated annually as a part of the process that sets import rights for the upcoming Capability Year, to determine the amount of External Installed Capacity that can be imported to the New York Control Area across any individual External Interface and across all of those External Interfaces, taken together. The External Installed Capacity deliverability test will be performed using the ISO's forecast, for the upcoming Capability Year, of New York Control Area CRIS resources, transmission facilities, and load. Under this process (i) Grandfathered External Installed Capacity Agreements listed in Attachment E of the ISO Installed Capacity Manual, and (ii) the Existing Transmission Capacity for Native Load listed for New York State Electric & Gas Corporation in Table 3 of Attachment L to the ISO OATT, will be considered deliverable within the Rest of State. Additionally, 1090 MW of imports made over the Quebec (via Chateauguay) Interface will be considered to be deliverable until the end of the 2010 Summer Capability Period.

The import limit set for External Installed Capacity not associated with UDRs, EDRs or External CRIS Rights will be set no higher than the amount of imports deliverable into Rest of State that (i) would not increase the LOLE as determined in the upcoming Capability Year IRM consistent with Section 2.7 of the NYISO Installed Capacity Manual, "Limitations on Unforced Capacity Flow in External Control Areas," (ii) are deliverable within the Rest of State Capacity Region when evaluated with the New York Control Area CRIS resources (including EDRs and

UDRs) and External CRIS Rights forecast for the upcoming Capability Year, and (iii) would not degrade the transfer capability of any Other Interface by more than the threshold identified in Section 25.7.9 of Attachment S to the ISO OATT. Import limits set for External Installed Capacity will reflect the modeling of awarded External CRIS rights, but the awarded External CRIS rights will not be adjusted as part of import limit-setting process. Procedures for qualifying selling, and delivery of External Installed Capacity are detailed in the Installed Capacity Manual.

Until the grandfathered import rights over the Quebec (via Chateauguay) Interface expire at the end of the 2010 Summer Capability Period, the 1090 MW of grandfathered import rights will be made available on a first-come, first-served basis pursuant to ISO Procedures. Any of the grandfathered import rights over the Quebec (via Chateauguay) Interface not utilized for a Capability Period will be made available to other external resources for that Capability Period, pursuant to ISO Procedures, to the extent the unutilized amount is determined to be deliverable.

Additionally, any of the Existing Transmission Capacity for Native Load listed for New York State Electric & Gas Corporation not utilized by New York State Electric & Gas Corporation for a Capability Period will be made available to other external resources for that Capability Period, pursuant to ISO procedures, to the extent the unutilized amount is determined to be deliverable within the Rest of State Capacity Region.

LSEs with External Installed Capacity as of the effective date of this Tariff will be entitled to designate External Installed Capacity at the same NYCA Interface with another Control Area, in the same amounts in effect on the effective date of this Tariff. To the extent such External Installed Capacity corresponds to Existing Transmission Capacity for Native Load as reflected in Table 3 of Attachment L to the ISO OATT, these External Installed Capacity rights will continue without term and shall be allocated to the LSE's retail access customers in accordance with the LSE's retail access program on file with the PSC and subject to any necessary filings with the Commission. External Installed Capacity rights existing as of September 17, 1999 that do not correspond to Table 3 of Attachment L to the ISO OATT shall survive for the term of the relevant External Installed Capacity contract or until the relevant External Generator is retired.

5.12.2.3 One-Time Conversion of Grandfathered Quebec (via Chateauguay) Interface Rights.

An entity can request to convert a specified number of MW, up to 1090 MW over the Quebec External Interface (via Chateauguay), into External CRIS Rights by making either a Contract Commitment or Non-Contract Commitment that satisfies the requirements of Section 25.7.11.1 of Attachment S to the ISO OATT. The converted number of MW will not be subject to further evaluation for deliverability within a Class Year Deliverability Study under Attachment S to the ISO OATT, as long as the External CRIS Rights are in effect.

5.12.2.3.1 The External CRIS Rights awarded under this conversion process will first become effective for the 2010-2011 Winter Capability Period.

5.12.2.3.2 Requests to convert these grandfathered rights must be received by the NYISO on or before 5:00 pm Eastern Time on February 1, 2010, with the following information: (a) a statement that the entity is electing to convert by satisfying the requirements of a Contract Commitment or a Non-Contract Commitment in accordance with Section 25.7.11.1 of Attachment S to the ISO OATT; (b) the length of the commitment in years; (c) for the Summer Capability Period, the requested number of MW; (d) for the Winter Capability Period, the Specified Winter Months, if any, and the requested number of MW; and (e) a minimum number of MW the entity will accept if granted ("Specified Minimum") for the Summer Capability Period and for all Specified Winter Months, if any.

5.12.2.3.3 An entity cannot submit one or more requests to convert in the aggregate more than 1090 MW in any single month.

5.12.2.3.4 If requests to convert that satisfy all other requirements stated herein are equal to or less than the 1090 MW limit, all requesting entities will be awarded the requested number of MW of External CRIS Rights. If conversion requests exceed the 1090 MW limit, the NYISO will prorate the allocation based on the weighted average of the requested MW times the length of the contract/commitment (*i.e.*, number of Summer Capability Periods) in accordance with the following formula:

$$\begin{aligned}&Rights\ allocated\ to\ entity\ i\\ &\qquad = 1090\\ &\qquad * (MW_i * contract/commitment\ length_i)\\ &\qquad / \sum_j \left(MW_j * contract/commitment\ length_j\right)\end{aligned}$$

j = l,…# entities requesting import rights

In the formula, contract/commitment length means the lesser of the requested contract/commitment length and twenty (20) years. The NYISO will perform separate calculations for the Summer and Winter Capability Periods. The NYISO will determine whether the prorated allocated number of MW for any requesting entity is less than the entity's Specified Minimum. If any allocation is less, the NYISO will remove such request(s) and recalculate the prorated allocations among the remaining requesting entities using the above formula. This process will continue until the prorated allocation meets or exceeds the specified minimum for all remaining requests.

5.12.2.3.5 Any portion of the previously grandfathered 1090 MW not converted through this process will no longer be grandfathered from deliverability. Previously grandfathered rights converted to External CRIS Rights but then terminated will no longer be grandfathered from deliverability.

5.12.2.4 Offer Cap Applicable to Certain External CRIS Rights

Notwithstanding any other capacity mitigation measures or obligations that may apply, the offers of External Installed Capacity submitted pursuant to a Non-Contract Commitment, as described in Section 25.7.11.1.2 of Attachment S of the ISO OATT, will be subject to an offer cap in each month of the Summer Capability Period and for all Specified Winter Months. This offer cap will be determined as the higher of:

5.12.2.4.1 1.1 times the price corresponding to all available Unforced Capacity determined from the NYCA ICAP Demand Curve for that Period; and

5.12.2.4.2 The most recent auction clearing price (a) in the External market supplying the External Installed Capacity, if any, and if none, then the most recent auction clearing price in an External market to which the capacity may be wheeled, less (b) any transmission reservation costs in the External market associated with providing the Installed Capacity, in accordance with ISO Procedures.

5.12.3 Installed Capacity Supplier Outage Scheduling Requirements

All Installed Capacity Suppliers, except for Control Area System Resources and Responsible Interface Parties, that intend to supply Unforced Capacity to the NYCA shall submit a confidential notification to the ISO of their proposed outage schedules in accordance with the ISO Procedures. Transmission Owners will be notified of these and subsequently revised outage schedules. Based upon a reliability assessment, if Operating Reserve deficiencies are projected to occur in certain weeks for the upcoming calendar year, the ISO will request voluntary rescheduling of outages. In the case of Installed Capacity Suppliers actually supplying Unforced Capacity to the NYCA, if voluntary rescheduling is ineffective, the ISO will invoke forced rescheduling of their outages to ensure that projected Operating Reserves over the upcoming year are adequate.

An Installed Capacity Supplier that refuses a forced rescheduling of its outages for any unit shall be prevented from supplying Unforced Capacity in the NYCA with that unit during any month where it undertakes such outages. The rescheduling process is described in the ISO Procedures.

An Installed Capacity Supplier that intends to supply Unforced Capacity in a given month that did not qualify as an Installed Capacity Supplier prior to the beginning of the Capability Period must notify the ISO in accordance with the ISO Procedures so that it may be subject to forced rescheduling of its proposed outages in order to qualify as an Installed Capacity Supplier. A Resource that refuses the ISO's forced rescheduling of its proposed outages shall not qualify as an Installed Capacity Supplier for that unit for any month during which it schedules or conducts an outage.

Outage schedules for External System Resources and Control Area System Resources shall be coordinated by the External Control Area and the ISO in accordance with the ISO Procedures.

5.12.4 Required Certification for Installed Capacity

(a) Each Installed Capacity Supplier must confirm to the ISO, in accordance with ISO Procedures that the Unforced Capacity it has certified has not been sold for use in an External Control Area.

(b) Each Installed Capacity Supplier holding rights to UDRs or EDRs from an External Control Area must confirm to the ISO, in accordance with ISO Procedures, that it will not use as self-supply or offer, and has not sold, Installed Capacity associated with the quantity of MW for which it has not made its one time capability adjustment year election pursuant to Section 5.11.4 (if applicable.)

(c) On and after the execution of an RMR Agreement, and for the duration of its term, an RMR Generator shall not enter into any new agreement or extend any other agreement that impairs or otherwise diminishes its ability to comply with its obligation under an RMR Agreement, or that limits its ability to provide Energy, Capacity, or Ancillary Services directly to the ISO Administered Markets. An Interim Service Provider that is required to keep its generating unit(s) in service shall not enter into any new agreement or extend any other agreement that limits its ability to provide Energy, Capacity, or Ancillary Services directly to the ISO Administered Markets or otherwise meet its obligations as an Interim Service Provider.

5.12.5 Operating Data Reporting Requirements

To qualify as Installed Capacity Suppliers in the NYCA, Resources shall submit to the ISO Operating Data in accordance with this Section 5.12.5 and the ISO Procedures. Resources that do not submit Operating Data in accordance with the following subsections and the ISO Procedures may be subject to the sanctions provided in Section 5.12.12.1 of this Tariff.

Resources that were not in operation on January 1, 2000 shall submit Operating Data to the ISO no later than one month after such Resources commence commercial operation, and in accordance with the ISO Procedures and the following subsections as applicable.

5.12.5.1 Generators, System Resources, Energy Limited Resources, Energy Storage Resources, Responsible Interface Parties, Intermittent Power Resources, Limited Control Run-of-River Hydro Resources and Municipally Owned Generation

To qualify as Installed Capacity Suppliers in the NYCA, Generators, External Generators, System Resources, External System Resources, Energy Limited Resources, Responsible Interface Parties, Intermittent Power Resources, Limited Control Run-of-River Hydro Resources, Energy Storage Resources, and municipally owned generation or the purchasers of Unforced Capacity associated with those Resources shall submit GADS Data, data equivalent to GADS Data, or other Operating Data to the ISO in accordance with the ISO Procedures. Prior to the successful implementation of a software modification that allows gas turbines to submit multiple bid points, these units shall not be considered to be forced out for any hours that the unit was available at its base load capability in accordance with the ISO Procedures. This section shall also apply to any Installed Capacity Supplier, External or Internal, using UDRs to meet Locational Minimum Installed Capacity Requirements.

5.12.5.2 Control Area System Resources

To qualify as Installed Capacity Suppliers in the NYCA, Control Area System Resources, or the purchasers of Unforced Capacity associated with those Resources, shall submit CARL

Data and actual system failure occurrences data to the ISO each month in accordance with the ISO Procedures.

5.12.5.3 Transmission Projects Granted Unforced Capacity Deliverability Rights

An owner of a transmission project that receives UDRs must, among other obligations, submit outage data or other operational information in accordance with the ISO procedures to allow the ISO to determine the number of UDRs associated with the transmission facility.

5.12.5.4 Transmission Projects Granted External-to ROS Deliverability Rights

An owner of a transmission project that receives EDRs must, among other obligations, submit outage data or other operational information when determined applicable by the ISO and in accordance with ISO Procedures.

5.12.5.5 Co-located Storage Resources

Generators that are Co-located Storage Resources must each, individually, comply with the requirements of Section 5.12.5.1 of this Services Tariff. Generators that are Co-located Storage Resources must submit outage data or other operational information in accordance with ISO Procedures that will allow the ISO to validate the CSR Scheduling Limits associated with the Co-located Storage Resources. CSR Scheduling Limits will be incorporated into each CSR Generator's UCAP calculation (*see* Services Tariff Section 5.12.6.2).

5.12.6 Capacity Calculations, Operating Data Default, Value and Collection

5.12.6.1 ICAP Calculation for Behind-the-Meter Net Generation Resources

The ISO shall calculate the amount of Net-ICAP for each Behind-the-Meter Net Generation Resource as the Adjusted DMGC of the Generator of the Behind-the-Meter Net

Generation Resource minus the Resource's Adjusted Host Load in accordance with this Tariff and ISO Procedures.

5.12.6.1.1 Adjusted DMGC

The ISO's calculation of the Adjusted DMGC of a Behind-the-Meter Net Generation Resource shall be the least of: (i) its DMGC for the Capability Period; (ii) its Adjusted Host Load plus its applicable Injection Limit; and (iii) its Adjusted Host Load plus the number of MW of CRIS it has obtained, as determined in accordance with OATT Section 25 (OATT Attachment S) and ISO Procedures.

If the Station Power of a Behind-the-Meter Net Generation Resource is separately metered from all other Load of the Resource, such that the Station Power Load can be independently measured and verified, the Generator of a Behind-the-Meter Net Generation Resource may elect to perform a DMNC Test instead of a DMGC Test pursuant to ISO Procedures. Such election must be made in writing to the ISO prior to the start of the DMNC Test Period.

If a Behind-the-Meter Net Generation Resource elects to take a DMNC Test, the Station Power measured during such DMNC Test shall not be included in the Resource's Host Load. A Behind-the-Meter Net Generation Resource's DMNC value for the Capability Period shall be used in lieu of a DMGC value in the calculation of the Resource's Adjusted DMGC for the purposes of Sections 5.12.6.1 and 5.12.6.2 of this Services Tariff.

5.12.6.1.2 Adjusted Host Load

A Behind-the-Meter Net Generation Resource's Adjusted Host Load shall be equal to the product of the Average Coincident Host Load multiplied by one plus the Installed Reserve Margin.

The Adjusted Host Load shall be calculated by the ISO on an annual basis prior to the start of the Summer Capability Period and in accordance with ISO Procedures, based upon the Behind-the-Meter Net Generation Resource's Average Coincident Host Load for the prior Summer Capability Period and the Winter Capability Period before that.

5.12.6.1.2.1 Average Coincident Host Load

The ISO must receive the Behind-the-Meter Net Generation Resource's applicable metered Load data required to calculate an Average Coincident Host Load in accordance with ISO Procedures. The ISO shall compute the Average Coincident Host Load for each Capability Year (i) using the metered Host Load data for the applicable NYCA peak Load hours, except as provided below in this Section, and (ii) adjusted for weather normalization and Load growth as determined by the ISO in relation to developing the NYCA Minimum Installed Capacity Requirement in accordance with ISO Procedures.

For each Capability Year, the NYISO shall use the average of the highest twenty (20) one-hour peak Loads of the Host Load of the Behind-the-Meter Net Generation Resource that occur during the top forty (40) NYCA peak Load hours of the prior Summer Capability Period and the Winter Capability Period before that to calculate the Average Coincident Host Load.

If a facility meets the criteria to be, and has not previously been, a Behind-the-Meter Net Generation Resource, but does not have all of the appropriate meter data, its Average Coincident Host Load shall be a value forecasted by the Behind-the-Meter Net Generation Resource. The Behind-the-Meter Net Generation Resource's forecast shall be based on actual meter data, or if not available, billing data or other business data of the Host Load. An estimated Average Coincident Host Load can only be applicable to a Behind-the-Meter Net Generation Resource until actual data becomes available, but in any event no longer than three (3) consecutive Capability Years beginning with the Capability Year it is first an Installed Capacity Supplier.

5.12.6.1.2.2 Determination of Adjusted Host Load

After the ISO has calculated a Behind-the-Meter Net Generation Resource's Average Coincident Host Load, it shall then apply the NYCA Installed Reserve Margin. The Behind-the-Meter Net Generation Resource's Adjusted Host Load will be established by multiplying the Resource's Average Coincident Host Load for the Capability Year by the quantity of one plus the NYCA Installed Reserve Margin.

5.12.6.2 UCAP Calculations

The ISO shall calculate for each Resource the amount of Unforced Capacity that each Installed Capacity Supplier is qualified to supply in the NYCA in accordance with formulae provided in the ISO Procedures. A Resource's Unforced Capacity will be the applicable Adjusted Installed Capacity multiplied by the quantity of 1 minus the Resource's derating factor.

The amount of Unforced Capacity that each Generator, except for the Generator of a Behind-the-Meter Net Generation Resource, System Resource, Energy Limited Resource, Special Case Resource, and municipally-owned generation is authorized to supply in the NYCA shall be based on the ISO's calculations of individual Equivalent Demand Forced Outage Rates.

The amount of Unforced Capacity that each Energy Storage Resource is authorized to supply in the NYCA shall be based on the individual availability of the Energy Storage Resource in the Real-Time Market and calculated by the ISO in accordance with ISO Procedures. Except as provided in Section 5.12.6.2.1 of this Services Tariff, this calculation shall not include hours in any month that the Energy Storage Resource was in an outage state that started on or after May 1, 2015 and that precluded its eligibility to participate in the Installed Capacity market. The amount of Unforced Capacity that an Energy Storage Resource that is participating as a part of a Co-located Storage Resource is authorized to supply in the NYCA shall account for reductions to the CSR Scheduling Limits, or the unavailability of the associated facilities, in accordance with ISO Procedures.

The amount of Unforced Capacity that each Control Area System Resource is authorized to supply in the NYCA shall be based on the ISO's calculation of each Control Area System Resource's availability. The amount of Unforced Capacity that each Intermittent Power Resource is authorized to supply in the NYCA shall be based on the ISO's calculation of the amount of capacity that the Intermittent Power Resource can reliably provide during system peak Load hours in accordance with ISO Procedures.

Starting with the Capability Year beginning May 1, 2021, this calculation will be weighted according to the respective Peak Load Window weighting factors provided in the table below. Separate Summer and Winter Peak Load Windows are applicable based on the penetration of duration limited resources in Section 5.12.14.

	Summer Peak Load Window		Winter Peak Load Window	
Hour Beginning	6 Hour	8 Hour	6 Hour	8 Hour
12		5.00%		
13	12.50%	10.00%		
14	18.75%	17.50%		5.00%
15	18.75%	17.50%		5.00%
16	18.75%	17.50%	18.75%	17.50%
17	18.75%	17.50%	18.75%	17.50%
18	12.50%	10.00%	18.75%	17.50%
19		5.00%	18.75%	17.50%
20			12.50%	10.00%
21			12.50%	10.00%

Except as provided in Section 5.12.6.2.1 of this Services Tariff, this calculation shall not include hours in any month that the Intermittent Power Resource was in an outage state that started on or after May 1, 2015 and that precluded its eligibility to participate in the Installed Capacity market.

The amount of Unforced Capacity that an Intermittent Power Resource that is participating as part of a Co-located Storage Resource is authorized to supply in the NYCA shall account for reductions to the CSR Scheduling Limits, or the unavailability of the associated facilities, in accordance with ISO Procedures.

The amount of Unforced Capacity that each Limited Control Run-of-River Hydro Resource is authorized to provide in the NYCA shall be determined separately for Summer and Winter Capability Periods as the rolling average of the hourly net Energy provided by each such Resource during the 20 highest NYCA integrated real-time load hours in each of the five previous Summer or Winter Capability Periods, as appropriate, stated in megawatts. Except as provided in Section 5.12.6.2.1 of this Services Tariff, for a Limited Control Run-of-River Hydro Resource in an outage state that started on or after May 1, 2015 and that precluded its eligibility to participate in the Installed Capacity market during one of the 20 highest NYCA integrated real-time load hours in any one of the five previous Summer or Winter Capability Periods, the ISO shall replace that Winter or Summer Capability Period, as appropriate, with the next most recent Winter or Summer Capability Period such that the rolling average of the hourly net Energy provided by each such Resource shall be calculated from the 20 highest NYCA integrated real-time load hours in the five most recent prior Summer or Winter Capability Periods in which the Resource was not in an outage state that precluded its eligibility to participate in the Installed Capacity market on one of the 20 highest NYCA integrated real-time load hours in that Capability Period.

Prior to Capability Year beginning May 1, 2021, the ISO shall calculate separate Summer and Winter Capability Period Unforced Capacity values for each Generator, System Resource, Special Case Resource, Energy Limited Resource, and municipally owned generation and update them periodically using a twelve-month calculation. Starting with the Capability Year beginning May 1, 2021, the ISO shall calculate separate Summer and Winter Capability Period Unforced Capacity values for each Special Case Resource and update them periodically using a twelve-month calculation in accordance with ISO Procedures. Starting with the Capability Year beginning May 1, 2021, the calculation for each Generator, System Resource, Energy Limited Resource, and municipally owned generation will use the months comprising the two most recent like Capability Periods in accordance with formulae provided in the ISO Procedures; provided, however, except as provided in Section 5.12.6.2.1 of this Services Tariff, for a Generator in an outage state that started on or after May 1, 2015 and that precluded its eligibility to participate in the Installed Capacity market at any time during any month from which GADS or other operating data would otherwise be used to calculate an individual Equivalent Demand Forced Outage Rate, the ISO shall replace such month's GADS or other operating data with GADS or other operating data from the most recent like month in which the Generator was not in an outage state that precluded its eligibility to participate in the Installed Capacity market.

The ISO shall calculate separate Summer and Winter Capability Period Unforced Capacity values for Energy Storage Resources and update them seasonally as described in ISO Procedures.

The ISO shall calculate separate Summer and Winter Capability Period Unforced Capacity values for Intermittent Power Resources and update them seasonally as described in ISO Procedures.

The amount of Unforced Capacity that each Behind-the-Meter Net Generation Resource is authorized to supply in the NYCA shall be its Net-UCAP. Net-UCAP is the lesser of (i) the ISO's calculation of the Generator of the Behind-the-Meter Net Generation Resource Adjusted DMGC multiplied by one minus its Equivalent Demand Forced Outage Rate, and then decreased by its Adjusted Host Load translated into Unforced Capacity terms consistent with Section 5.11.1 of this Tariff, and (ii) the Resource's Net-ICAP.

5.12.6.2.1 Exceptions

A Resource returning to the Energy market after taking an outage that precluded its participation in the Installed Capacity market and which returns with modifications to its operating characteristics determined by the ISO to be material and which, therefore, requires the submission of a new Interconnection Request will receive, as the initial derating factor for calculation of the Resource's Unforced Capacity upon its return to service, the derating factor it would have received as a newly connecting unit in lieu of a derating factor developed from unit-specific data. A Resource returning to the Energy market after taking an outage that precluded its participation in the Installed Capacity market and which, upon its return, uses as its primary fuel a fuel not previously used at the facility for any purpose other than for ignition purposes will receive, as the initial derating factor for calculation of the Resource's Unforced Capacity upon its return to service, the default derating factor in lieu of a derating factor developed from unit-specific data even if the modifications to allow use of a new primary fuel are not material and do not require the submission of a new Interconnection Request.

This Section 5.12.6.2.1 shall apply to a Resource returning to the Energy market after taking an outage that started on or after May 1, 2015 and that precluded its participation in the Installed Capacity market.

5.12.6.3 Default Unforced Capacity

In its calculation of Unforced Capacity, the ISO shall deem a Resource to be completely forced out for each month for which the Resource has not submitted its Operating Data in accordance with Section 5.12.5 of this Tariff and the ISO Procedures. A Resource that has been deemed completely forced out for a particular month may submit new Operating Data, for that month, to the ISO at any time. The ISO will use such new Operating Data when calculating, in a timely manner in accordance with the ISO Procedures, an Unforced Capacity value for the Resource.

Upon a showing of extraordinary circumstances, the ISO retains the discretion to accept at any time Operating Data which have not been submitted in a timely manner, or which do not fully conform with the ISO Procedures.

5.12.6.4 Exception for Certain Equipment Failures

When a Generator, Special Case Resource, Energy Limited Resource, or System Resource is forced into an outage by an equipment failure that involves equipment located on the high voltage side of the electric network beyond the step-up transformer, and including such step-up transformer, the outage will not be counted for purposes of calculating that Resource's Equivalent Demand Forced Outage Rate.

5.12.6.5 Unforced Capacity, Outage Data and Operational Information Associated with External-to-ROS Deliverability Rights

The ISO shall calculate the availability of the External interface associated with each project granted EDRs, in accordance with ISO Procedures. The availability factor (percentage) of the interface will be used to reduce the amount of EDRs for which Unforced Capacity may be offered. This calculation is distinct from and in addition to the calculation the ISO performs for each Installed Capacity Resource qualified for use with EDRs.

5.12.7 Availability Requirements

Subsequent to qualifying, each Installed Capacity Supplier shall, except as noted in Section 5.12.11 of this Tariff, on a daily basis: (i) schedule a Bilateral Transaction; (ii) Bid Energy in each hour of the Day-Ahead Market in accordance with the applicable provisions of Section 5.12.1 of this Tariff; or (iii) notify the ISO of any outages.

Installed Capacity Suppliers with Energy Duration Limitations corresponding to a Duration Adjustment Factor, as described in Section 5.12.14 below, must on a daily basis during the Peak Load Window and for the number of consecutive hours that correspond to its Energy Duration Limitation, or for the entirety of the Peak Load Window for an Energy Storage Resource : (i) schedule a Bilateral Transaction; (ii) Bid Energy in the Day-Ahead Market in accordance with the applicable provisions of Section 5.12.1 of this Tariff; or (iii) notify the ISO of any outages. The ISO may adjust the Peak Load Window that Installed Capacity Suppliers with Energy Duration Limitations will be responsible for scheduling, bidding, or notifying for, with scheduling or bidding in hours outside the Peak Load Window in Section 5.12.14. An RMR Generator can only schedule a Bilateral Transaction to the extent expressly authorized in its RMR Agreement.

The total amount of Energy that an Installed Capacity Supplier schedules, bids, or declares to be unavailable on a given day must equal or exceed the Installed Capacity Equivalent of the Unforced Capacity it supplies.

For Energy Storage Resources without an Energy Duration Limitation, the total amount of Energy that is scheduled, Bid, or declared to be unavailable shall also include the maximum of the Energy Storage Resource's (i) negative Installed Capacity Equivalent, or (ii) Lower Operating Limit, such that amount scheduled, Bid, or declared to be unavailable reflects the entire withdrawal to injection operating range. Energy Storage Resources with an Energy Duration Limitation must, on a daily basis, and for each hour outside of the Peak Load Window: (i) Bid in the Day-Ahead Market in accordance with the applicable provisions of Section 5.12.1 of this Tariff; or (ii) notify the ISO of any outages, the maximum of the Energy Storage Resource's (a) negative Installed Capacity Equivalent, or (b) Lower Operating Limit. The amount scheduled, Bid, and/or declared to be unavailable must reflect the Energy Storage Resource's entire withdrawal operating range.

5.12.7.1 Co-located Storage Resource Availability Requirements

In addition to independently satisfying the requirements of Section 5.12.7 for each Generator that participates in a Co-located Storage Resource, each Installed Capacity Supplier must, on a daily basis, and for each hour of the Day-Ahead Market Day: (i) provide a CSR injection Scheduling Limit; and (ii) notify the ISO of any derate or outage to the interconnection facilities comprising the point of interconnection. The sum of the CSR injection Scheduling Limit and the derate or outage must equal or exceed the sum of the Installed Capacity Equivalent of the Unforced Capacity supplied by the Intermittent Power Resource and the applicable Section 5.12.7 hourly Bid, Schedule, or Notify obligation of the Energy Storage Resource. Each

Installed Capacity Supplier must also on a daily basis, and for each hour of the Day-Ahead Market Day: (i) provide a CSR withdrawal Scheduling Limit; and (ii) notify the ISO of any derate or outage to the interconnection facilities comprising the point of interconnection. The sum of the CSR withdrawal Scheduling Limit and the derate or outage must equal or exceed the Energy Storage Resource's applicable 5.12.7 hourly Bid, Schedule, or Notify obligation.

5.12.8 Unforced Capacity Sales

Each Installed Capacity Supplier will, after satisfying the deliverability requirements set forth in the applicable provisions of Attachment X, Attachment Z and Attachment S to the ISO OATT, be authorized to supply an amount of Unforced Capacity during each Obligation Procurement Period, based on separate seasonal Unforced Capacity calculations performed by the ISO for the Summer and Winter Capability Periods. Unforced Capacity may be sold in six-month strips, or in monthly, or multi-monthly segments.

External Unforced Capacity (except External Installed Capacity associated with UDRs) may only be offered into Capability Period Auctions or Monthly Auctions for the Rest of State, and ICAP Spot Market Auctions for the NYCA, and may not be offered into a Locality for an ICAP Auction. Bilateral Transactions which certify External Unforced Capacity using Import Rights, EDRs, or External CRIS Rights may not be used to satisfy a Locational Minimum Unforced Capacity Requirement.

UCAP from an RMR Generator may only be offered into the ICAP Spot Market Auction, except and only to the extent that the RMR Agreement expressly permits the RMR Generator's UCAP to be certified in a Bilateral Transaction.

If an Energy Limited Resource's, Generator's, System Resource's or Control Area System Resource's DMNC rating, or the DMGC rating of a Generator of a Behind-the-Meter

Net Generation Resource, if applicable, is determined to have increased during an Obligation Procurement Period, pursuant to testing procedures described in the ISO Procedures, the amount of Unforced Capacity that it shall be authorized to supply in that or future Obligation Procurement Periods shall also be increased on a prospective basis in accordance with the schedule set forth in the ISO Procedures provided that it first has satisfied the deliverability requirements set forth in the applicable provisions of Attachment X, Attachment Z and Attachment S to the ISO OATT.

New Generators and Generators that have increased their Capacity since the previous Summer Capability Period due to changes in their generating equipment may, after satisfying the deliverability requirements set forth in the applicable provisions of Attachment X, Attachment Z and Attachment S to the ISO OATT, qualify to supply Unforced Capacity on a foregoing basis during the Summer Capability Period based upon a DMNC test, or the DMGC test of a Generator of a Behind-the-Meter Net Generation Resource, that is performed and reported to the ISO after March 1 and prior to the beginning of the Summer Capability Period DMNC Test Period. The Generator will be required to verify the claimed DMNC or DMGC rating by performing an additional test during the Summer DMNC Test Period. Any shortfall between the amount of Unforced Capacity supplied by the Generator for the Summer Capability Period and the amount verified during the Summer DMNC Test Period will be subject to deficiency charges pursuant to Section 5.14.2 of this Tariff. The deficiency charges will be applied to no more than the difference between the Generator's previous Summer Capability Period Unforced Capacity and the amount of Unforced Capacity equivalent the Generator supplied for the Summer Capability Period.

New Generators and Generators that have increased their Capacity since the previous Winter Capability Period due to changes in their generating equipment may, after satisfying the deliverability requirements set forth in the applicable provisions of Attachment X, Attachment Z and Attachment S to the ISO OATT, qualify to supply Unforced Capacity on a foregoing basis during the Winter Capability Period based upon a DMNC test, or the DMGC test of a Generator of a Behind-the-Meter Net Generation Resource, that is performed and reported to the ISO after September 1 and prior to the beginning of the Winter Capability Period DMNC Test Period. The Generator will be required to verify the claimed DMNC or DMGC rating by performing an additional test during the Winter Capability Period DMNC Test Period. Any shortfall between the amount of Unforced Capacity certified by the Generator for the Winter Capability Period and the amount verified during the Winter Capability Period DMNC Test Period will be subject to deficiency charges pursuant to Section 5.14.2 of this Tariff. The deficiency charges will be applied to no more than the difference between the Generator's previous Winter Capability Period Unforced Capacity and the amount of Unforced Capacity equivalent the Generator supplied for the Winter Capability Period.

Any Installed Capacity Supplier, except as noted in Section 5.12.11 of this ISO Services Tariff, which fails on a daily basis to schedule, Bid, or declare to be unavailable in the Day-Ahead Market an amount of Unforced Capacity, expressed in terms of Installed Capacity Equivalent, that it certified for that day, rounded down to the nearest 0.1 MW, or rounded down to the nearest whole MW for an External Installed Capacity Supplier, is subject to sanctions pursuant to Section 5.12.12.2 of this Tariff. If an entity other than the owner of an Energy Limited Resource, Generator, System Resource, Behind-the-Meter Net Generation Resource, or Control Area System Resource that is providing Unforced Capacity is responsible for fulfilling bidding, scheduling, and notification requirements, the owner and that entity must designate to the ISO which of them will be responsible for complying with the scheduling, bidding, and notification requirements. The designated bidding and scheduling entity shall be subject to sanctions pursuant to Section 5.12.12.2 of this ISO Services Tariff.

5.12.9 Sales of Unforced Capacity by System Resources

Installed Capacity Suppliers offering to supply Unforced Capacity associated with Internal System Resources shall submit for each of their Resources the Operating Data and DMNC testing data or historical data described in Sections 5.12.1 and 5.12.5 of this ISO Services Tariff in accordance with the ISO Procedures. Such Installed Capacity Suppliers will be allowed to supply the amount of Unforced Capacity that the ISO determines pursuant to the ISO Procedures to reflect the appropriate Equivalent Demand Forced Outage Rate. Installed Capacity Suppliers offering to sell the Unforced Capacity associated with System Resources may only aggregate Resources in accordance with the ISO Procedures.

5.12.10 Curtailment of External Transactions In-Hour

All Unforced Capacity that is not out of service, or scheduled to serve the Internal NYCA Load in the Day-Ahead Market may be scheduled to supply Energy for use in External Transactions provided, however, that such External Transactions shall be subject to Curtailment within the hour, consistent with ISO Procedures. Such Curtailment shall not exceed the Installed Capacity Equivalent committed to the NYCA.

5.12.11 Responsible Interface Parties, Municipally-Owned Generation, Energy Limited Resources, Intermittent Power Resources, and Installed Capacity Suppliers with Energy Duration Limitations

5.12.11.1 Responsible Interface Parties

Responsible Interface Parties may qualify as Installed Capacity Suppliers, without having to comply with the daily bidding, scheduling, and notification requirements set forth in Section 5.12.7 of this Tariff, if their Special Case Resources are available to operate at the direction of the ISO in order to reduce Load from the NYS Transmission System and/or the distribution system for a minimum of four (4) consecutive hours each day, following notice of the potential need to operate twenty-one (21) hours in advance if notification is provided by 3:00 P.M. ET, or twenty-four (24) hours in advance otherwise, and a notification to operate two (2) hours ahead. Special Case Resources will be considered to have a four (4) hour Energy Duration Limitation to align with their obligation. In order for a Responsible Interface Party to enroll an SCR that uses an eligible Local Generator, any amount of generation that can reduce Load from the NYS Transmission System and/or distribution system at the direction of the ISO that was produced by the Local Generator during the hour coincident with the NYCA or Locality peaks, upon which the LSE Unforced Capacity Obligation of the LSE that serves that SCR is based, must be accounted for when the LSE's Unforced Capacity Obligation for the upcoming Capability Year is established. Responsible Interface Parties must provide this generator data in accordance with ISO Procedures so that the ISO can adjust upwards the LSE Unforced Capacity Obligation to prevent double-counting.

Responsible Interface Parties supplying Unforced Capacity cannot offer the Demand Reduction associated with such Unforced Capacity in the Emergency Demand Response Program. A Resource with sufficient metering to distinguish MWs of Demand Reduction may participate as a Special Case Resource and in the Emergency Demand Response Program provided that the same MWs are not committed both as Unforced Capacity and to the Emergency Demand Response Program.

The ISO will have discretion, pursuant to ISO Procedures, to exempt Local Generators that are incapable of starting in two (2) hours from the requirement to operate on two (2) hours notification. Local Generators that can be operated to reduce Load from the NYS Transmission System and/or distribution system at the direction of the ISO and Loads capable of being interrupted upon demand, that are not available on certain hours or days will be derated by the ISO, pursuant to ISO Procedures, to reflect the Load serving equivalence of the hours they are actually available.

Responsible Interface Parties must submit a Minimum Payment Nomination, in accordance with ISO Procedures. The ISO may request Special Case Resource performance from less than the total number of Special Case Resources within the NYCA or a Load Zone in accordance with ISO Procedures.

Special Case Resources with Local Generators that can be operated to reduce Load from the NYS Transmission System and/or distribution system at the direction of the ISO and Special Case Resources with Loads capable of being interrupted upon demand will be required to comply with verification and validation procedures set forth in the ISO Procedures. Such procedures will not require metering other than interval billing meters on customer Load or testing other than DMNC or sustained disconnect, as appropriate, unless agreed to by the customer, except that Special Case Resources not called to supply Energy in a Capability Period will be required to run a test once every Capability Period in accordance with the ISO Procedures.

Unforced Capacity supplied in a Bilateral Transaction by a Special Case Resource pursuant to this subsection may only be resold if the purchasing entity or the Installed Capacity Marketer has agreed to become a Responsible Interface Party and comply with the ISO notification requirements for Special Case Resources. LSEs and Installed Capacity Marketers may become Responsible Interface Parties and aggregate Special Case Resources and sell the Unforced Capacity associated with them in an ISO-administered auction if they comply with ISO notification requirements for Special Case Resources.

Responsible Interface Parties that were requested to reduce Load in any month shall submit performance data to the NYISO, within 75 days of each called event or test, in accordance with ISO Procedures. Failure by a Responsible Interface Party to submit performance data for any Special Case Resources required to respond to the event or test within the 75-day limit will result in zero performance attributed to those Special Case Resources for purposes of satisfying the Special Case Resource's capacity obligation as well as for determining energy payments. All performance data are subject to audit by the NYISO and its market monitoring unit. If the ISO determines that it has made an erroneous payment to a Responsible Interface Party, the ISO shall have the right to recover it either by reducing other payments to that Responsible Interface Parties or by resolving the issue pursuant to other provisions of this Services Tariff or other lawful means.

Provided the Responsible Interface Party supplies evidence of such reductions in 75 days, the ISO shall pay the Responsible Interface Party that, through their Special Case Resources, caused a verified Load reduction in response to (i) an ISO request to perform due to a forecast reserve shortage (ii) an ISO declared Major Emergency State, (iii) an ISO request to perform made in response to a request for assistance for Load relief purposes or as a result of a Local

Reliability Rule, or (iv) a test called by the ISO, for such Load reduction, in accordance with ISO Procedures. Subject to performance evidence and verification, in the case of a response pursuant to clauses (i), (ii), of (iii) of this subsection, Suppliers that schedule Responsible Interface Parties shall be paid the zonal Real-Time LBMP for the period of requested performance or four (4) hours, whichever is greater, in accordance with ISO Procedures; provided, however, Special Case Resource Capacity shall settle Demand Reductions, in the interval and for the capacity for which Special Case Resource Capacity has been scheduled Day-Ahead to provide Operating Reserves, Regulation Service or Energy, as being provided by a Supplier of Operating Reserves, Regulation Service or Energy.

In the event that a Responsible Interface Party's Minimum Payment Nomination for a Special Case Resource, for the number of hours of requested performance or the minimum four (4) hour period, whichever is greater, exceeds the LBMP revenue received, the Special Case Resource will be eligible for a Bid Production Cost Guarantee to make up the difference, in accordance with Section 4.23 of this Services Tariff and ISO Procedures; provided, however, the ISO shall 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. Subject to performance evidence and verification, in the case of a response pursuant to clause (iv) of this subsection, payment for participation in tests called by the ISO shall be equal to the zonal Real Time LBMP for the MWh of Energy reduced within the test period.

Transmission Owners that require assistance from enrolled Special Case Resources with Local Generators larger than 100 kW and Special Case Resources with Loads capable of being interrupted upon demand for Load relief purposes or as a result of a Local Reliability Rule, shall direct their requests for assistance to the ISO for implementation consistent with the terms of this section. Within Load Zone J, participation in response to an ISO request to perform made as a result of a request for assistance from a Transmission Owner for less than the total number of Special Case Resources, for Load relief purposes or as a result of a Local Reliability Rule, in accordance with ISO Procedures, shall be voluntary and the responsiveness of the Special Case Resource shall not be taken into account for performance measurement.

5.12.11.1.1 Special Case Resource Average Coincident Load

The ISO must receive from the Responsible Interface Party that enrolls a Special Case Resource, the applicable metered Load data required to calculate an ACL for that SCR as provided below and in accordance with ISO Procedures. The ACL shall be computed using the metered Load for the applicable Capability Period SCR Load Zone Peak Hours that indicates the Load consumed by each SCR that is supplied by the NYS Transmission System and/or distribution system and is exclusive of any generation produced by a Local Generator, other behind-the-meter generator, or other supply source located behind the SCR's meter, that served some of the SCR's Load.

Beginning with the Winter 2011-2012 Capability Period and thereafter, the ISO shall use the average of the highest twenty (20) one-hour peak Loads of the SCR taken from the Load data reported for the Capability Period SCR Load Zone Peak Hours during the Prior Equivalent Capability Period, and taking into account the resource's reported verified Load reduction in a Transmission Owner's demand response program in hours coincident with any of these hours, to create a SCR ACL baseline. In addition, beginning with the Summer 2014 Capability Period, the resource's verified Load reduction in either of the ISO's economic demand response programs (the Day Ahead Demand Response Program and the Demand Side Ancillary Services Program) in hours coincident with any of the applicable Capability Period SCR Load Zone Peak Hours will be taken into account when creating the SCR ACL. For the Day Ahead Demand Response Program, the verified Load reduction that occurred in response to a DADRP schedule shall be added to the Capability Period SCR Load Zone Peak Hour for which the reduction in response to a DADRP schedule occurred. For the Demand Side Ancillary Services Program, the Load value to be used in calculating the ACL for each hour during the Capability Period SCR Load Zone Peak Hours in which a non-zero Base Point Signal the ISO provides to the resource, shall be the greater of (a) the DSASP Baseline MW value in the interval immediately preceding the first non-zero Base Point Signal in the Capability Period SCR Load Zone Peak Hour and (b) the metered Load of the resource as reported by the RIP for the Capability Period SCR Load Zone Peak Hour. When the non-zero Base Point Signal dispatch of a DSASP resource begins in one hour and continues into consecutive hours, and the consecutive hour is identified as being a Capability Period SCR Load Zone Peak Hour, the DSASP Baseline MW value in effect at the beginning of the dispatch of the non-zero Base Point Signal shall be the MW value used for purposes of determining the applicable Load value for that Capability Period SCR Load Zone Peak Hour, in accordance with the preceding sentence. The ISO will post to its website the Capability Period SCR Load Zone Peak Hours for each zone ninety (90) days prior to the beginning of the Capability Period for which the ACL will be in effect.

In the SCR enrollment file uploaded by the RIP each month within the Capability Period, among other required information, the RIP shall provide the SCR’s metered Load values for the applicable Capability Period SCR Load Zone Peak Hours necessary to compute the ACL for each SCR.

The exception to this requirement to report the required metered Load data for the ACL, when enrolling a SCR prior to the Summer 2014 Capability Period, is if (i) the SCR has not previously been enrolled with the ISO and (ii) never had interval metering Load data for each month in the Prior Equivalent Capability Period needed to compute the SCR's ACL. Beginning with the Summer 2014 Capability Period, the exception to this requirement to report the required metered Load data for the ACL, is dependent upon one or more of the eligibility conditions for SCR enrollment with a Provisional ACL provided in Section 5.12.11.1.2 of this Services Tariff and ISO Procedures. For SCRs that meet the criteria to enroll with a Provisional ACL, the ISO must receive from the RIP a Provisional ACL as provided in Section 5.12.11.1.2 of this Services Tariff and in accordance with ISO Procedures.

Beginning with the Summer 2014 Capability Period, in addition to the requirement for RIPs to report each SCR's metered Load values that occurred during the Capability Period SCR Load Zone Peak Hours, in accordance with this Services Tariff and ISO Procedures during the enrollment process, any qualifying increase in a SCR's Load that will be supplied by the NYS Transmission System and/or distribution system may be reported as an Incremental ACL, subject to the limitations and verification reporting requirements provided in Section 5.12.11.1.5 of this Services Tariff and in accordance with ISO Procedures. Incremental ACL values must be reported using the required enrollment file that may be uploaded by the RIP during each month's enrollment period. RIPs may not report Incremental ACL values for any SCRs that are enrolled in the Capability Period with a Provisional ACL.

A reduction in a SCR's Load that is supplied by the NYS Transmission System and/or distribution system and meets the criteria for a SCR Change of Status must be reported as a SCR

Change of Status as provided by Section 5.12.11.1.3 of this Services Tariff and in accordance with ISO Procedures.

The ACL is the basis for the upper limit of ICAP, except in circumstances when the SCR has reported a SCR Change of Status or reported an Incremental ACL pursuant to Sections 5.12.11.1.3 and 5.12.11.1.5 of this Services Tariff. The basis for the upper limit of ICAP for a SCR that has experienced a SCR Change of Status or reported an Incremental ACL shall be the Net ACL.

5.12.11.1.2 Use of a Provisional Average Coincident Load

Prior to the Summer 2014 Capability Period, as provided in Section 5.12.11.1.1 of this Services Tariff, if a new Special Case Resource has not previously been enrolled with the ISO and never had interval billing meter data from the Prior Equivalent Capability Period, its Installed Capacity value shall be its Provisional Average Coincident Load for the Capability Period for which the new SCR is enrolled. The Provisional ACL may be applicable to a new SCR for a maximum of three (3) consecutive Capability Periods, beginning with the Capability Period in which the SCR is first enrolled.

Beginning with the Summer 2014 Capability Period, a SCR may be enrolled using a Provisional ACL in lieu of an ACL when one of the following conditions has been determined by the ISO to apply: (i) the SCR has not previously been enrolled with the ISO for the seasonal Capability Period for which the SCR enrollment with a Provisional ACL is intended, (ii) the SCR was enrolled with a Provisional ACL in the Prior Equivalent Capability Period and was required to report fewer than twenty (20) hours of metered Load verification data that correspond with the Capability Period SCR Load Zone Peak Hours based on the meter installation date of the SCR, (iii) the RIP attempting to enroll the SCR with a Provisional ACL is not the same RIP that enrolled the SCR in the Prior Equivalent Capability Period and interval billing meter data for the SCR from the Prior Equivalent Capability Period is not obtainable by the enrolling RIP and not available to be provided to the enrolling RIP by the ISO. The Provisional ACL may be applicable to a SCR for a maximum of three (3) consecutive Capability Periods when enrolled with the same RIP, beginning with the Capability Period in which the SCR is first enrolled by the RIP.

A SCR enrolled in the Capability Period with a Provisional ACL may not be enrolled by another RIP for the remainder of the Capability Period and the Provisional ACL value shall apply to the resource for the entire Capability Period for which the value is established.

The Provisional ACL is the RIP's forecast of the SCR's ACL and shall be the basis for the upper limit of ICAP for which the RIP may enroll the SCR during the Capability Period.

Any SCR enrolled with a Provisional ACL shall be subject to actual in-period verification. A Verified ACL shall be calculated by the ISO using the top twenty (20) one-hour peak Loads reported for the SCR from the Capability Period SCR Load Zone Peak Hours that are applicable to verify the Provisional ACL in accordance with ISO Procedures and taking into account the resource's reported verified Load reductions in a Transmission Owner's demand response program that are coincident with any of the applicable Capability Period SCR Load Zone Peak Hours. In addition, beginning with the Summer 2014 Capability Period, the resource's verified Load reduction in either of the ISO's economic demand response programs (the Day Ahead Demand Response Program and the Demand Side Ancillary Services Program) in hours coincident with any of the applicable Capability Period SCR Load Zone Peak Hours will be taken into account when creating the SCR Verified ACL. For the Day Ahead Demand Response Program, the verified Load reduction that occurred in response to a DADRP schedule shall be added to the Capability Period SCR Load Zone Peak Hour for which the reduction in response to a DADRP schedule occurred. For the Demand Side Ancillary Services Program, the Load value to be used in calculating the Verified ACL for each hour during the Capability Period SCR Load Zone Peak Hours in which a non-zero Base Point Signal the ISO provides to the resource, shall be the greater of (a) the DSASP Baseline MW value in the interval immediately preceding the first non-zero Base Point Signal in the Capability Period SCR Load Zone Peak Hour and (b) the metered Load of the resource as reported by the RIP for the Capability Period SCR Load Zone Peak Hour. When the non-zero Base Point Signal dispatch of a DSASP resource begins in one hour and continues into consecutive hours, and the consecutive hour is identified as being a Capability Period SCR Load Zone Peak Hour, the DSASP Baseline MW value in effect at the beginning of the dispatch of the non-zero Base Point Signal shall be the MW value used for purposes of determining the applicable Load value for that Capability Period SCR Load Zone Peak Hour, in accordance with the preceding sentence.

Following the Capability Period for which a resource with a Provisional ACL was enrolled, the RIP shall provide to the ISO the metered Load data required to compute the Verified ACL of the resource. The ISO shall compare the Provisional ACL to the Verified ACL to determine, after applying the applicable performance factor, whether the UCAP of the SCR had been oversold and whether a shortfall has occurred as provided under Section 5.14.2 of this Services Tariff. If the RIP fails to provide verification data required to compute the Verified ACL of the resource enrolled with a Provisional ACL by the deadline: (a) the Verified ACL of the resource shall be set to zero for each Capability Period in which the resource with a Provisional ACL was enrolled and verification data was not reported, and (b) the RIP may be subject to penalties in accordance with this Services Tariff.

5.12.11.1.3 Reporting a SCR Change of Load or SCR Change of Status

5.12.11.1.3.1 SCR Change of Load

The Responsible Interface Party shall report any SCR Change of Load in accordance with ISO Procedures. The RIP is required to document the SCR Change of Load and when the total Load reduction for SCRs that have a SCR Change of Load within the same Load Zone is greater than or equal to 5 MWs, the RIP shall report the SCR Change of Load for each SCR in accordance with ISO Procedures.

5.12.11.1.3.2 SCR Change of Status

The Responsible Interface Party shall report any SCR Change of Status in accordance with ISO Procedures. The ISO shall adjust the reported ACL of the SCR for a reported SCR Change of Status to the Net ACL, for all prospective months to which the SCR Change of Status is applicable. When a SCR Change of Status is reported under clause (i), (ii) or (iii) within the definition of a Qualified Change of Status Condition and the SCR has sold capacity, the SCR shall be evaluated for a potential shortfall under Section 5.14.2 of this Services Tariff. Failure by the RIP to report a SCR Change of Status shall be evaluated as a potential shortfall under Section 5.14.2 of this Service Tariff and evaluated for failure to report under Section 5.12.12.2 of this Services Tariff.

Beginning with the Summer 2014 Capability Period, SCRs that were required to perform in the first performance test in the Capability Period in accordance with ISO Procedures and that subsequently report or change a reported SCR Change of Status value after the first performance test in the Capability Period shall be required to demonstrate the performance of the resource against the Net ACL value in the second performance test in the Capability Period. The exceptions to this provision occur when a SCR's eligible Installed Capacity is set to zero throughout the period of the SCR Change of Status, when a SCR's eligible Installed Capacity is decreased by at least the same kW value as the reported SCR Change of Status, or if a SCR Change of Status is reported, and prior to the second performance test, the SCR returns to the full applicable ACL enrolled prior to the SCR Change of Status. Performance in both performance tests shall be used in calculation of the resource's performance factors and all associated performance factors, deficiencies and penalties. If the RIP fails to report the performance for a resource that was required to perform in the second performance test in the Capability Period: (a) the resource will be assigned a performance of zero (0) for the test hour, and (b) the RIP shall be evaluated for failure to report under Section 5.12.12.2 of this Services Tariff.

5.12.11.1.4 Average Coincident Load of an SCR Aggregation

The ISO shall compute the Average Coincident Load of an SCR Aggregation each month in accordance with ISO Procedures.

5.12.11.1.5 Use of an Incremental Average Coincident Load

Beginning with the Summer 2014 Capability Period, a Responsible Interface Party may report any qualifying increase to a Special Case Resource's Average Coincident Load as Incremental Average Coincident Load in the RIP enrollment file upload and in accordance with this Services Tariff and ISO Procedures.

For SCRs with a total Load increase equal to or greater than twenty (20) percent and less than thirty (30) percent of the applicable ACL, the RIP may enroll the SCR with an Incremental ACL provided that the eligible Installed Capacity does not increase from the prior enrollment months within the same Capability Period and prior to enrollment with an Incremental ACL. If the SCR is enrolled with an Incremental ACL and it is the first month of the SCR's enrollment in the applicable Capability Period, the enrolled eligible Installed Capacity value shall not exceed the maximum eligible Installed Capacity of the SCR from the Prior Equivalent Capability Period. When no enrollment exists for the SCR in the Prior Equivalent Capability Period and it is the first month of the SCR's enrollment in the applicable Capability Period, the enrolled eligible Installed Capacity of the SCR shall not exceed the ACL calculated from the Capability Period SCR Load Zone Peak Hours. For SCRs with a total Load increase equal to or greater than thirty (30) percent of the applicable ACL, the RIP may enroll the SCR with an Incremental ACL and an increase to the SCR's eligible Installed Capacity and is required to test as described in this section of the Service Tariff.

The ISO shall adjust the ACL of the SCR for an Incremental ACL for all months for which the Incremental ACL is reported by the RIP. For resources reporting an Incremental ACL, the Net ACL shall equal the enrolled ACL plus the reported Incremental ACL less any applicable SCR Change of Status and shall be the basis for the upper limit of ICAP for which the RIP may enroll the SCR during the Capability Period.

An Incremental ACL is a discrete change to the SCR operations that is expected to result in an increase to the Load that the SCR will consume from the NYS Transmission System and/or distribution system. It is not available to account for random fluctuations in Load, such as those caused by weather or other seasonal Load variations. Therefore, the ACL of a SCR may only be increased once per Capability Period and the amount of the increase enrolled must remain the same for all months for which the Incremental ACL is reported. A SCR enrolled in the Capability Period with an Incremental ACL may not be enrolled by another RIP for the remainder of the Capability Period. A SCR enrolled in the Capability Period with a Provisional ACL is not eligible to enroll with an Incremental ACL.

Following the Capability Period for which a SCR has been enrolled with an Incremental ACL, the RIP shall provide the hourly metered Load verification data that corresponds to the Monthly SCR Load Zone Peak Hours identified by the ISO for all months in which an Incremental ACL value was reported for the SCR. For each month for which verification data was required to be reported, the ISO shall calculate a Monthly ACL that will be used in the calculation of a Verified ACL. The Monthly ACL shall equal the average of the SCR's top twenty (20) one-hour metered Load values that correspond with the applicable Monthly SCR Load Zone Peak Hours, and taking into account (i) the resource's reported verified Load reduction in a Transmission Owner's demand response program in hours coincident with any of these hours and (ii) the resource's verified Load reduction in either of the ISO's economic demand response programs (the Day Ahead Demand Response Program and the Demand Side Ancillary Services Program) in hours coincident with any of these hours. For the Day Ahead Demand Response Program, the verified Load reduction that occurred in response to a DADRP schedule shall be added to the Monthly SCR Load Zone Peak Hour for which the reduction in response to a DADRP schedule occurred. For the Demand Side Ancillary Services Program, the Load value to be used in calculating the Monthly ACL for each hour during the Monthly SCR Load Zone Peak Hours in which a non-zero Base Point Signal the ISO provides to the resource, shall be the greater of (a) the DSASP Baseline MW value in the interval immediately preceding the first non-zero Base Point Signal in the Monthly SCR Load Zone Peak Hour and (b) the metered Load of the resource as reported by the RIP for the Monthly SCR Load Zone Peak Hour. When the non-zero Base Point Signal dispatch of a DSASP resource begins in one hour and continues into consecutive hours, and the consecutive hour is identified as being a Monthly SCR Load Zone Peak Hour, the DSASP Baseline MW value in effect at the beginning of the dispatch of the non-zero Base Point Signal shall be the MW value used for purposes of determining the applicable Load value for that Monthly SCR Load Zone Peak Hour, in accordance with the preceding sentence. The Verified ACL shall be the average of the two (2) highest Monthly ACLs during the Capability Period in which the SCR was enrolled with an Incremental ACL within the same Capability Period.

For any month in which verification data for the Incremental ACL is required but not timely submitted to the ISO in accordance with ISO procedures, the ISO shall set the metered Load values to zero. When a Monthly ACL is set to zero, the Verified ACL will be calculated as the average of: a) the two (2) highest Monthly ACLs during the Capability Period in which the SCR was enrolled with an Incremental ACL within the same Capability Period; plus b) the Monthly ACLs for all months in which the SCR was enrolled within the same Capability Period with an Incremental ACL in the Capability Period in which the RIP failed to provide the minimum verification data required. In addition, a RIP may be subject to a penalty for each month for which verification data was required and not reported in accordance with this Services Tariff.

For each SCR that is enrolled with an Incremental ACL, the ISO shall compare the Net ACL calculated from the resource enrollment (ACL plus Incremental ACL less any applicable SCR Change of Status) to the Verified ACL calculated for the SCR to determine if the RIP's use of an Incremental ACL may have resulted in a shortfall pursuant to Section 5.14.2.

A Special Case Resource that was required to perform in the first performance test in the Capability Period in accordance with ISO Procedures and was subsequently enrolled using an Incremental ACL and an increase in the amount of Installed Capacity that the SCR is eligible to sell, shall be required to demonstrate performance against the maximum amount of eligible

Installed Capacity reported for the SCR in the second performance test in the Capability Period. Performance in this test shall be measured from the Net ACL. Performance in both performance tests shall be used in calculation of the resource's performance factor and all associated performance factors, deficiencies and penalties. If the RIP fails to report the performance for a resource that was required to perform in the second performance test in the Capability Period: (a) the resource will be assigned a performance of zero (0) for the test hour, and (b) the RIP shall be evaluated for failure to report under Section 5.12.12.2 of this Services Tariff.

5.12.11.2 Existing Municipally-Owned Generation

A municipal utility that owns existing generation in excess of its Unforced Capacity requirement, net of NYPA-provided Capacity may, consistent with the deliverability requirements set forth in Attachment X and Attachment S to the ISO OATT, offer the excess Capacity for sale as Installed Capacity provided that it is willing to operate the generation at the ISO's request, and provided that the Energy produced is deliverable to the New York State Power System. Such a municipal utility shall not be required to comply with the requirement of Section 5.12.7 of this Tariff that an Installed Capacity Supplier bid into the Energy market or enter into Bilateral Transactions. Municipal utilities shall, however, be required to submit their typical physical operating parameters, such as their start-up times, to the ISO. This subsection is only applicable to municipally-owned generation in service or under construction as of December 31, 1999.

5.12.11.3 Energy Limited Resources

An Energy Limited Resource may, consistent with the deliverability requirements set forth in Attachment X and Attachment S to the ISO OATT, qualify as an Installed Capacity Supplier if it Bids its Installed Capacity Equivalent into the Day-Ahead Market each day and if it is able to provide the Energy equivalent of the Unforced Capacity for the number of consecutive hours that correspond to its Energy Duration Limitation each day. Energy Limited Resources shall also Bid a Normal Upper Operating Limit or Emergency Upper Operating Limit, as applicable, designating their desired operating limits. Energy Limited Resources that are not scheduled in the Day-Ahead Market to operate at a level above their bid-in upper operating limit, may be scheduled in the RTC, or may be called in real-time pursuant to a manual intervention by ISO dispatchers, who will account for the fact that Energy Limited Resource may not be capable of responding.

5.12.11.4 Intermittent Power Resources

Intermittent Power Resources that depend upon wind or solar as their fuel may qualify as Installed Capacity Suppliers, without having to comply with the daily bidding and scheduling requirements set forth in Section 5.12.7 of this Tariff, and may, consistent with the deliverability requirements set forth in Attachment X and Attachment S to the ISO OATT, claim up to their nameplate Capacity as Installed Capacity. To qualify as Installed Capacity Suppliers, such Intermittent Power Resources shall comply with the requirements of Section 5.12.1 and the outage notification requirements of 5.12.7 of this Tariff.

5.12.11.5 Installed Capacity Suppliers with an Energy Duration Limitation

A Resource with an Energy Duration Limitation may, consistent with the deliverability requirements set forth in Attachment X and Attachment S to the ISO OATT, qualify as an Installed Capacity Supplier with an Energy Duration Limitation if it Bids its Installed Capacity Equivalent into the Day-Ahead Market each day and if it is able to provide the Energy equivalent of the Unforced Capacity for the number of consecutive hours that correspond to its Energy Duration Limitation each day. Installed Capacity Suppliers with an Energy Duration Limitation shall also Bid a Normal Upper Operating Limit or Emergency Upper Operating Limit, as applicable, designating their desired operating limits. Installed Capacity Suppliers with an Energy Duration Limitation that are not scheduled in the Day-Ahead Market to operate at a level above their bid-in upper operating limit, may be scheduled in the RTC, or may be called in real-time pursuant to a manual intervention by ISO dispatchers, who will account for the fact that Installed Capacity Suppliers with an Energy Duration Limitation may not be capable of responding.

5.12.12 Sanctions Applicable to Installed Capacity Suppliers and Transmission Owners

Pursuant to this section, the ISO may impose financial sanctions on Installed Capacity Suppliers and Transmission Owners that fail to comply with certain provisions of this Tariff. The ISO shall notify Installed Capacity Suppliers and Transmission Owners prior to imposing any sanction and shall afford them a reasonable opportunity to demonstrate that they should not be sanctioned and/or to offer mitigating reasons why they should be subject to a lesser sanction. The ISO may impose a sanction lower than the maximum amounts allowed by this section at its sole discretion. Installed Capacity Suppliers and Transmission Owners may challenge any sanction imposed by the ISO pursuant to the ISO Dispute Resolution Procedures.

Any sanctions collected by the ISO pursuant to this section will be applied to reduce the Rate Schedule 1 charge under this Tariff.

5.12.12.1 Sanctions for Failing to Provide Required Information

If (i) an Installed Capacity Supplier fails to provide the information required by Sections 5.12.1.1, 5.12.1.2, 5.12.1.3, 5.12.1.4, 5.12.1.7 or 5.12.1.8 of this Tariff in a timely fashion, or (ii) a Supplier of Unforced Capacity from External System Resources located in an External Control

Area or from a Control Area System Resource that has agreed not to Curtail the Energy associated with such Installed Capacity, or to afford it the same Curtailment priority that it affords its own Control Area Load, fails to provide the information required for certification as an Installed Capacity Supplier established in the ISO Procedures, the ISO may take the following actions: On the first day that required information is late, the ISO shall notify the Installed Capacity Supplier that required information is past due and that it reserves the right to impose financial sanctions if the information is not provided by the end of the following day. Starting on the third day that the required information is late, the ISO may impose a daily financial sanction of up to the higher of $500 or $5 per MW of Installed Capacity that the Generator, System Resource, or Control Area System Resource in question is capable of providing. Starting on the tenth day that the required information is late, the ISO may impose a daily financial sanction of up to the higher of $1000 or $10 per MW of Installed Capacity that the Generator, System Resource, or Control Area System Resource in question is capable of providing.

If an Installed Capacity Supplier fails to provide the information required by Subsection 5.12.1.5 of this Tariff in a timely fashion, the ISO may take the following actions: On the first calendar day that required information is late, the ISO shall notify the Installed Capacity Supplier that required information is past due and that it reserves the right to impose financial sanctions if the information is not provided by the end of that first calendar day. Starting on the second calendar day that the required information is late, the ISO may impose a daily financial sanction up to the higher of $500 or $5 per MW of Installed Capacity that the Generator, System Resource, or Control Area System Resource in question is capable of providing.

If a TO fails to provide the information required by Subsection 5.11.3 of this Tariff in a timely fashion, the ISO may take the following actions: On the first day that required information is late, the ISO shall notify the TO that required information is past due and that it reserves the right to impose financial sanctions if the information is not provided by the end of the following day. Starting on the third day that the required information is late, the ISO may impose a daily financial sanction up to $5,000 a day. Starting on the tenth day that required information is late, the ISO may impose a daily financial sanction up to $10,000.

5.12.12.2 Sanctions for Failing to Comply with Scheduling, Bidding, and Notification Requirements

On any day in which an Installed Capacity Supplier fails to comply with the scheduling, bidding, or notification requirements of Sections 5.12.1.6 or 5.12.1.10, or with Section 5.12.7 of this Tariff, or in which a Supplier of Installed Capacity from External System Resources or Control Area System Resources located in an External Control Area that has agreed not to Curtail the Energy associated with such Installed Capacity, or to afford it the same Curtailment priority that it affords its own Control Area Load, fails to comply with scheduling, bidding, or notification requirements for certification as an Installed Capacity Supplier established in the ISO Procedures, the ISO may impose a financial sanction up to the product of a deficiency charge (pro-rated on a daily basis for Installed Capacity Suppliers) and the maximum number of MWs that the Installed Capacity Supplier failed to schedule or Bid in any hour in that day provided, however, that no financial sanction shall apply to any Installed Capacity Supplier who demonstrates that the Energy it schedules, bids, or declares to be unavailable on any day is not less than the Installed Capacity that it supplies for that day rounded down to the nearest 0.1 MW, or rounded down to the nearest whole MW for an External Installed Capacity Supplier. For Installed Capacity Suppliers that have an Energy Duration Limitation, the deficiency charge will be pro-rated on a daily basis only taking into account hours during the Peak Load Window corresponding with the Resource’s Energy Duration Limitation obligation, excluding Energy

Storage Resources which will be evaluated over all hours during the Peak Load Window, and the maximum number of MWs that the Installed Capacity Supplier with an Energy Duration Limitation failed to schedule or Bid in any hour in the Peak Load Window of that day provided, however, that no financial sanction shall apply to any Installed Capacity Supplier that demonstrates that the Energy it schedules, bids, or declares to be unavailable on any day is not less than the Installed Capacity that it supplies for that day rounded down to the nearest 0.1 MW. The deficiency charge may be up to one and one-half times the applicable Market-Clearing Price of Unforced Capacity determined in the ICAP Spot Market Auction corresponding to where the Installed Capacity Supplier's capacity cleared, and for each month in which the Installed Capacity Supplier is determined not to have complied with the foregoing requirements.

In addition to the financial sanctions described above, the Installed Capacity Supplier offering a Generator that participates as a Co-located Storage Resource may also be subject to a financial sanction for failing to comply with the requirements of Services Tariff Section 5.12.7.1. When such Installed Capacity Supplier fails to comply with Services Tariff Section 5.12.7.1, the ISO may impose a financial sanction up to the product of a deficiency charge and the difference between Installed Capacity Equivalent of the Unforced Capacity of the Generator and the CSR Scheduling Limit. If an Installed Capacity Supplier is subject to financial sanctions for its failure to comply with Services Tariff Section 5.12.7.1 is also subject to a penalty under this Section for failing to comply with the scheduling, bidding, or notification requirements of Sections 5.12.1.6 or 5.12.1.10, or with Section 5.12.7 of this Tariff for the same Day-Ahead Market hour, the NYISO shall assess only the greater of the two sanctions for that hour.

In addition, if any Installed Capacity Supplier fails to comply with the scheduling, bidding, or notification requirements of Sections 5.12.1.6 or 5.12.1.10, or with Section 5.12.7 of this Tariff, or if an Installed Capacity Supplier of Unforced Capacity from an External Control Aria fails to comply with the scheduling, bidding, or notification requirements for certification as an Installed Capacity Supplier established in the ISO Procedures, during an hour in which the ISO curtails Exports associated with NYCA Installed Capacity Suppliers consistent with Section 5.12.10 of this Tariff and with ISO Procedures, then the ISO may impose an additional financial sanction equal to the product of the number of MWs the Installed Capacity Supplier failed to schedule during that hour and the corresponding Real-Time LBMP at the applicable Proxy Generator Bus.

To the extent an Installed Capacity Supplier of Unforced Capacity from an External Control Area or an External Generator associated with an Unforced Capacity sale using UDRs or EDRs fails to comply with Section 5.12.1.10 of this Tariff, the Installed Capacity Supplier or External Generator associated with an Unforced Capacity sale using UDRs or EDRs shall be subject to a deficiency charge calculated in accordance with the formula set forth below for each Obligation Procurement Period:

$$Deficiency\ charge = 1.5 * PRICE * \left(\frac{1000kW}{1MW}\right) * \left(\frac{\sum_{n=1}^{N}\left(\max(\ ICAP_n^{MWh} -\ SRE_n^{MWh}, 0)\right)}{N}\right)$$

Where:

N = total number of hours of SRE calls during the relevant Obligation Procurement Period

PRICE = ICAP Spot Market Auction clearing price for the relevant Obligation Procurement Period

$ICAP_n^{MWh}$ = for each hour *n* of SRE calls during the relevant Obligation Procurement Period, the ICAP equivalent of the UCAP sold from the External Installed Capacity Supplier that is a Generator, or the External Generator associated with an Unforced Capacity sale using UDRs or EDRs, or the Control Area System Resource in MWh, minus (x) any MWh that are unavailable due to an outage as defined in the ISO Procedures, or due to due to physical operating limitations affecting the External Installed Capacity Supplier that is a Generator, or the External Generator associated with an Unforced Capacity sale using UDRs or EDRs, or due to other operational issues that the ISO determines to be outside the Installed Capacity Supplier's control, and (y) any MWh that were Bid as Imports to the NYCA at the appropriate Proxy Generator Bus at a price that was designed to ensure the Import was scheduled to the greatest extent possible, but that were not scheduled by the ISO

SRE_n^{MWh} = MWh provided to the NYCA at the appropriate Proxy Generator Bus from the External Installed Capacity Supplier that is a Generator, or the External Generator associated with an Unforced Capacity sale using UDRs or EDRs, or the Control Area System Resource, during each hour *n* of SRE calls during the relevant Obligation Procurement Period.

If an Installed Capacity Supplier's failure to fully comply with this Tariff would, in addition to being assessed a deficiency charge calculated in accordance with the formula set forth above, also permit the ISO to impose a different deficiency charge or a financial sanction under this Section 5.12.12.2, or to impose a deficiency charge for a shortfall under Section 5.14.2.2 of this Tariff, then the ISO shall only impose the penalty for failure to comply with Section 5.12.1.10 of this Tariff on the Installed Capacity Supplier for the hour(s) in which the Installed Capacity Supplier failed to meet its obligations under Section 5.12.1.10 of this Tariff.

If the Installed Capacity Supplier is a Responsible Interface Party that enrolled a SCR with an Incremental ACL in accordance with this Services Tariff, and also reported an increase to the Installed Capacity the SCR has eligible to sell after the first performance test in the Capability Period, the ISO may impose an additional financial sanction due to the failure of the RIP to report the required performance of the SCR against the Net ACL value in the second performance test in the Capability Period. This sanction shall be the value of the reported increase in the eligible Installed Capacity associated with the SCR that was sold by the RIP in each month of the Capability Period, during which the reported increase was in effect, multiplied by up to one and one-half times the applicable Market-Clearing Price of Unforced Capacity determined in the ICAP Spot Market Auction for each such month.

If the Installed Capacity Supplier is a Responsible Interface Party, and the Average Coincident Load of the Special Case Resource has been decreased after the first performance test in the Capability Period, due to a SCR Change of Status in accordance with this Services Tariff and ISO Procedures, the ISO may impose an additional financial sanction resulting from the failure of the RIP to report the required performance of the SCR against the Net ACL value of the SCR when the SCR was required to perform in the second performance test in the Capability Period in accordance with Section 5.12.11.1.3.2 of this Services Tariff. This sanction shall be the value of the Unforced Capacity equivalent of the SCR Change of Status MW reported for the SCR during the months for which the SCR was enrolled with a SCR Change of Status and was required to demonstrate in the second performance test as specified in Section 5.12.11.1.3.2 of this Services Tariff, multiplied by up to one and one-half times the applicable Market-Clearing Price of Unforced Capacity determined in the ICAP Spot Market Auction for each such month.

If a RIP fails to provide the information required by Section 5.12.11.1.3 of this Services Tariff in accordance with the ISO Procedures for reporting a Qualified Change of Status Condition, and the ISO determines that a SCR Change of Status occurred within a Capability Period, the ISO may impose a financial sanction equal to the difference, if positive, between the enrolled ACL and the maximum one hour metered Load for the month multiplied by up to one-half times the applicable Market-Clearing Price of Unforced Capacity determined in the ICAP Spot Market Auction for each month the Installed Capacity Supplier is deemed to have a shortfall in addition to the corresponding shortfall penalty as provided in Section 5.14.2.

For each month in which a RIP fails to report required verification data and the applicable ACL value is set to zero in accordance with Section 5.12.11 of this Services Tariff, the ISO shall have the right to recover any energy payments made to the RIP for performance of the SCR by reducing other payments or other lawful means.

5.12.14 Energy Duration Limitations and Duration Adjustment Factors for Installed Capacity Suppliers

Starting with the Capability Year that begins on May 1, 2021, Resources with a limited run-time that meet the Energy Duration Limitations identified in the tables below may qualify to participate as Installed Capacity Suppliers. Resources with a limited run-time must elect an Energy Duration Limitation that is less than or equal to the Resource's ability to demonstrate sustained output at its qualified MW amount. Resources that do not have an Energy Duration Limitation will have a Duration Adjustment Factor of 100%. The Adjusted Installed Capacity for an Installed Capacity Supplier shall be calculated using the applicable Energy Duration Limitations and Duration Adjustment Factors, and in accordance with ISO Procedures, starting with the 2021/2022 Capability Year, as determined by the MW count of incremental penetration of Resources with Energy Duration Limitations as listed below:

Table 1:

Incremental Penetration of Resources with Energy Duration Limitations is less than 1000 MW	
Energy Duration Limitations (hours)	Duration Adjustment Factor (%)
8	100
6	100
4	90
2	45

Table 2:

Incremental Penetration of Resources with Energy Duration Limitations 1000 MW and above	
Energy Duration Limitations (hours)	Duration Adjustment Factor (%)
8	100
6	90
4	75
2	37.5

While Table 1 is in effect, Resources with an Energy Duration Limitation of 6 hours or less must fulfill the availability requirements given in Section 5.12.7 for a 6-hour Peak Load Window. While Table 2 is in effect, Resources with an Energy Duration Limitation of 6 hours or less must fulfill the availability requirements given in Section 5.12.7 for an 8-hour Peak Load Window. Resources with an Energy Duration Limitation of 8 hours must always fulfill the availability requirements given in Section 5.12.7 for an 8-hour Peak Load Window. The 6 hour Peak Load Window for the Summer Capability Period is HB 13 through HB 18, and the 6 hour Peak Load Window for the Winter Capability Period is HB 16 through HB 21. The 8 hour Peak

Load Window for the Summer Capability Period is HB 12 through HB 19, and the 8 hour Peak Load Window for the Winter Capability Period is HB 14 through HB 21.

5.12.14.1 Counting Incremental Penetration of Resources with Energy Duration Limitations

The penetration levels of CRIS MW will be the sum of CRIS for Resources with Energy Duration Limitations that have elected to participate in ISO Administered Markets with less than 8 hour duration and that have entered into service after January 1, 2019 and incremental CRIS awarded after January 1, 2019 to Resources with Energy Duration Limitations that have elected to participate in ISO Administered Markets with less than 8 hour duration as specified below.

Penetration levels of CRIS MW for Resources with Energy Duration Limitations will be calculated in accordance with ISO Procedures as the sum of CRIS for Resources with Energy Duration Limitations of 2 hours, CRIS for Resources with Energy Duration Limitations of 4 hours and CRIS for Resources with Energy Duration Limitations of 6 hours that have entered into service and have participated in the ISO Markets after January 1, 2019. Penetration levels of Demand Side Resources will be calculated as the sum of the Demand Side Resource MW that have elected to participate in the ISO Capacity markets with less than 8 hour duration as of July 1, as pursuant to ISO Procedures. The MW count of Resources with Energy Duration Limitations that were in service prior to January 1, 2019 and have Retired will include CRIS for Resources with Energy Duration Limitations of 2 hours, CRIS for Resources with Energy Duration Limitations of 4 hours and CRIS for Resources with Energy Duration Limitations of 6 hours that have Retired as of July 1 each year, pursuant to ISO Procedures. Resources that obtained CRIS and were in service prior to January 1, 2019 that qualify as Resources with Energy Duration Limitations at a later date will not be included in the penetration levels of Resources with Energy Duration Limitations.

The MW count of incremental penetration of Resources with Energy Duration Limitations used to determine the applicable Duration Adjustment Factors provided in Section 5.12.14 for the upcoming Capability Year will be calculated in accordance with ISO Procedures as the sum of the penetration levels of CRIS MW, as described above, and penetration levels of Demand Side Resources, as described above, less the sum of CRIS MW for Resources with Energy Duration Limitations that have Retired, as described above, and less 1309.1 MW of SCR MW. The MW count of incremental penetration of Resources with Energy Duration Limitations with their Energy Duration Limitation election will be counted as of July 1 and posted by July 15. Once there are 1000 MW or more incremental penetration of Resources with Energy Duration Limitations, the Duration Adjustment Factors listed in Table 2 provided above in Section 5.12.14 will be effective May 1 of the following Capability Year and Table 2 will be effective notwithstanding future MW count of incremental penetration of Resources with Energy Duration Limitations.

5.12.14.2 Adjusted Installed Capacity

Starting with the Capability Year beginning May 1, 2021, a Resource's Unforced Capacity shall reflect the applicable Duration Adjustment Factor for the Resource's elected Energy Duration Limitation. The Adjusted Installed Capacity is equal to a Resource's Installed Capacity multiplied by the Duration Adjustment Factor. If a Resource or Aggregation wants to change its duration election it must inform the ISO by August 1 preceding the upcoming Capability Year.

5.12.14.3 Periodic Review of Capacity Values

Starting in 2022 and occurring every four (4) years, the independent consultant for the ISO shall perform a review of the Capacity Values to re-evaluate the reliability benefit of

Resources with Energy Duration Limitations in meeting Resource Adequacy criteria for the four (4) year period coinciding with the four (4) Capability Years covered by the next Demand Curve Reset filing, pursuant to Services Tariff Section 5.14.1.2.2. The periodic review shall: (i) identify the methodologies and data used to determine the Duration Adjustment Factors, (ii) evaluate the appropriate Energy Duration Limitations, (iii) re-evaluate the Duration Adjustment Factors for Resources with Energy Duration Limitations, (iv) re-evaluate the Peak Load Window associated with the bidding requirement for Resources with Energy Duration Limitations specified below, and (v) re-evaluate the hourly weighting factors percentages during the Peak Load Window for Intermittent Power Resources.

The periodic review shall be conducted in accordance with the schedule and procedures specified in the ISO Procedures. A proposed schedule will be reviewed with stakeholders no later than September 1 of the second year prior to the Demand Curve Reset filing year, pursuant to Section 5.14.1.2.2. The schedule and procedures shall provide for:

5.12.14.3.1 ISO development, with stakeholder review and comment, of a request for study, scope, assumptions, and methodology to provide consulting services to determine recommended values for the Duration Adjustment Factors specified above, and appropriate methodologies for such determination;

5.12.14.3.2 Selection of a consultant in accordance with the request in Section 5.12.14.3.1;

5.12.14.3.3 Submission to the ISO and the stakeholders of a draft report from the consultant on the consultant's determination of recommended values for the Energy Duration Limitations and the associated Duration Adjustment Factors, and Peak Load Windows specified above;

5.12.14.3.4 Stakeholder review of and comment on the data, assumptions and conclusions in the consultant's draft report, with participation by the responsible person or persons providing the consulting services;

5.12.14.3.5 An opportunity for the Market Monitoring Unit to review and comment on the draft request for the proposals, the consultant's report, and the ISO's proposed Energy Duration Limitations and the associated Duration Adjustment Factors, Peak Load Windows for Resources with Energy Duration Limitations (the responsibilities of the Market Monitoring Unit that are addressed in this section of the Service's Tariff are also addressed in Section 30.4.6.3.1 of Attachment O), and Peak Load Windows Intermittent Power Resources;

5.12.14.3.6 Issuance by the consultant of a final report;

5.12.14.3.7 Issuance of a draft of the ISO's recommended adjustments to the Energy Duration Limitations and the associated Duration Adjustment Factors, Peak Load Windows for Resources with Energy Duration Limitations, and Peak Load Windows for Intermittent Power Resources for stakeholder review and comment; and

5.12.14.3.8 Issuance of the ISO's proposed Energy Duration Limitations and the associated Duration Adjustment Factors, Peak Load Windows for Resources with Energy Duration Limitations, and Peak Load Windows for Intermittent Power Resources, taking into account the report of the consultant, the recommendations of the Market Monitoring Unit, and the views of the stakeholders together with the rationale for accepting or rejecting any such inputs.

5.18 Generator Outages and Generator Obligations While in These Outages

This Section 5.18 shall apply to a Generator in any outage state that started on or after May 1, 2015.

A Market Participant with a Generator in the NYCA that is in any outage state shall report this status to the ISO pursuant to ISO Procedures.

Except when a Generator is not subject to the requirements of this Section 5.18 because it is only participating in the ISO Markets as part of an Aggregation, if the Market Participant that administers a Generator's participation in the ISO Administered Markets is a different entity than the entity that possesses the ultimate decision-making authority concerning the deactivation , outage or repair of the Generator, then the entity with ultimate decision-making authority regarding the deactivation, outage or repair of the Generator must agree, as part of the registration of the Generator with the ISO for participation in the ISO Administered Markets, that it will be subject to and comply with the outage state rules set forth in this Section 5.18 of the ISO Services Tariff. Except when a Generator is not subject to the requirements of this Section 5.18 because it is only participating in the ISO Markets as part of an Aggregation, the entity with ultimate decision-making authority regarding the deactivation, retirement and/or repair of the Generator shall, along with the Market Participant, be subject to all of the requirements of Section 5.18 of the ISO Services Tariff that apply to a Market Participant.

5.18.1 Forced Outages and Commenced Repair Determinations

5.18.1.1 A Market Participant with a Generator in a Forced Outage shall keep the ISO informed as to progress of its Generator's repairs pursuant to ISO Procedures. A Market Participant may keep its Generator in a Forced Outage beyond the last day of the month which contains the 180th day of its Forced

Outage only if it has Commenced Repair of its Generator. A Market Participant that anticipates its Generator will not be able to return to the Energy market before the last day of the month which contains the 180th day of its Forced Outage and which desires to remain eligible to be in the Installed Capacity market beyond the 180th day shall provide a Repair Plan to the ISO by the 120th day of the Forced Outage.

5.18.1.2 A Repair Plan shall include a work plan, with milestones, or set of necessary actions, and shall provide the time it is expected to take to complete each task and describe the repair of the Generator's equipment related to electric production, fuel or station power supply or transmission interconnection, as appropriate, that was either affected by the Forced Outage or otherwise makes the unit available for the Energy market. The Repair Plan's milestones shall include, in appropriate circumstances: damage assessments, engineering assessments, initial cost estimates, purchase orders, inspection reports, initial safety assessments, hazardous material abatement plans, and labor mobilization plans. The Repair Plan shall include the date the Market Participant expects the Generator to be repaired and available for the Energy market (return date) which return date: i) shall be reasonable, ii) may be provided as a good faith estimate, and iii) shall be updated to the extent new information becomes available. The return date or good faith estimate of a return date that a Market Participant provides for its Generator shall be reasonable if it is comparable to the return date that would be included in a Credible Repair Plan pursuant to Section 5.18.1.5 of this Services Tariff.

5.18.1.3 Market Participants requesting that the NYISO determine, pursuant to Services Tariff Section 23.4.5.6.2, that their Generator has experienced a Catastrophic Failure, or that Exceptional Circumstances will delay the submission of data necessary for the ISO to perform an audit and review pursuant to Section 23.4.5.6.2, shall submit their requests, with necessary supporting data, to the NYISO by the 120th day of the Forced Outage if they desire the determination to be issued by the 160th day of the Forced Outage of their Generator.

5.18.1.4 A Market Participant has Commenced Repair of its Generator if it: i) has decided to pursue the repair of its Generator, and based on the ISO's technical/engineering evaluation, ii) has a Repair Plan for the Generator that is consistent with a Credible Repair Plan, and iii) has made appropriate progress in pursuing the repair of its Generator when measured against the milestones of a Credible Repair Plan.

5.18.1.5 For purposes of the determinations required by Section 5.18.1.3(ii) and (iii), and 5.18.1.6 of this Services Tariff, a Credible Repair Plan is the Repair Plan that would be expected from a supplier: i) with a generating facility that is reasonably the same as or similar to the type and vintage of the Generator; ii) intending to return its generating facility to service. A Credible Repair Plan for a Generator that suffered a Forced Outage is a Repair Plan that would also be expected from a supplier with a generating facility that suffered a forced outage that was reasonably the same as or comparable to the Forced Outage suffered by the Generator and which forced outage occurred under the same, or reasonably similar, circumstances as the Generator's. A Credible Repair Plan for a Generator in a Mothball Outage is a Repair Plan that would also be expected from a supplier pursuing a repair to its generating facility which repair is reasonably the same as or comparable to the repair being pursued by the Generator.

5.18.1.6 The determination that a Market Participant has Commenced Repair of its Generator in a Forced Outage shall be made by the ISO by the 160th day of the Forced Outage. If the Market Participant provides updated information after the 120th day of the Forced Outage and before the 180th day of its Generator's Forced Outage, the ISO will, as applicable, take such information into consideration to make its determination or it will update its previously issued determination to the extent practicable.

The determination that a Market Participant has Commenced Repair of its Generator in an ICAP Ineligible Forced Outage, which Market Participant has been determined by the ISO to have one or more Exceptional Circumstances that delay the acquisition of necessary data for an audit and review for economic justification pursuant to Section 23.4.5.6.2 of this Services Tariff, shall be made by the ISO as soon as practicable following receipt of necessary data.

The determination that a Market Participant has Commenced Repair of its Generator in an ICAP Ineligible Forced Outage or Mothball Outage, which Market Participant is seeking to toll expiration of its outage and CRIS rights pursuant to Sections 5.18.2.3.2 or 5.18.3.3.2 of this Services Tariff, will be made by the ISO as soon as practicable following receipt of the necessary data.

5.18.1.7 If a Market Participant has not Commenced Repair of its Generator by the last day of the month which contains the 180th day of the Forced Outage, the

Generator's Forced Outage shall expire on the last day of the month which contains the 180th day of the Forced Outage. The Forced Outage of a Generator that Commenced Repair but ceased or unreasonably delayed the Generator's repair shall terminate on the last day of the month containing the date that the Market Participant ceased or unreasonably delayed the repair. The ISO will determine a Market Participant has unreasonably delayed the repair of its Generator if such delay would not have been included in a Credible Repair Plan from a supplier experiencing the situation which caused the Market Participant to delay the repair of its Generator.

5.18.1.8 Upon the expiration or termination of a Generator's Forced Outage, the Generator shall be in an ICAP Ineligible Forced Outage unless the Generator has been Retired by the Market Participant.

5.18.2 ICAP Ineligible Forced Outage

5.18.2.1 A Market Participant may voluntarily reclassify its Generator from a Forced Outage to an ICAP Ineligible Forced Outage only if the Generator has been in a Forced Outage for at least sixty (60) days. A Generator that has been voluntarily reclassified from a Forced Outage to an ICAP Ineligible Forced Outage shall begin its ICAP Ineligible Forced Outage on the first day of the month following the month in which it was voluntarily reclassified to an ICAP Ineligible Forced Outage.

A Generator in an ICAP Ineligible Forced Outage as a result of the expiration or termination of its Forced Outage pursuant to Section 5.18.1.6 of this Services Tariff, shall begin its ICAP Ineligible Forced Outage on the day following the day the Generator's Forced Outage expired or terminated.

A Generator in an ICAP Ineligible Forced Outage as a result of substantial actions that have been taken, such as dismantling or disabling essential equipment, which actions are inconsistent with an intention to operate the Generator in the Energy market shall begin its ICAP Ineligible Forced Outage on the day following the day such actions began.

If one of the two Generators in a CSR enters an ICAP Ineligible Forced Outage but the other CSR Generator continues operating, the remaining Generator may continue to participate as a Generator in a CSR unless or until the Generator in the ICAP Ineligible Forced Outage becomes Retired.

5.18.2.2 A Generator in an ICAP Ineligible Forced Outage is not eligible to participate in the Installed Capacity market and shall automatically cease to qualify to participate in the Installed Capacity market beginning with the first day of its ICAP Ineligible Forced Outage. The Generator shall no longer be ineligible to participate in the Installed Capacity market**,** by virtue of its ICAP Ineligible Forced Outage, as of the first day the Generator returns to operation and offers its Energy into the Day-Ahead Market without declaring an outage. The month for which the Generator will first be eligible to participate in the Installed Capacity market will be based on the date the Generator returns to operation and offers its Energy into the Day-Ahead Market without declaring an outage and ISO Procedures.

5.18.2.3 ICAP Ineligible Force Outage Expiration

5.18.2.3.1 Except as provided in Section 5.18.2.3.2, a Generator's ICAP Ineligible

Forced Outage shall expire if: i) its CRIS rights have expired; or ii) it did not have CRIS rights and has been in the ICAP Ineligible Forced Outage for 36 consecutive months. A Generator shall be Retired if its ICAP Ineligible Forced Outage expires.

5.18.2.3.2 If a Market Participant with a Generator in an ICAP Ineligible Forced Outage has Commenced Repair prior to when the ICAP Ineligible Forced Outage would expire pursuant to Section 5.18.2.3.1 and has provided a reasonable return date as that term is described in Section 5.18.1.2 of this Services Tariff that occurs after such expiration date, then the outage and the Generator's CRIS rights will be tolled until, and the ICAP Ineligible Forced Outage will expire on, the earlier of: i) 120 days from when the outage would have expired under Section 5.18.2.3.1; or ii) an ISO determination that the Market Participant has ceased or unreasonably delayed the repair of its Generator. The ISO will determine if a Market Participant has unreasonably delayed the repair of its Generator if such delay would not have been included in a Credible Repair Plan from a supplier experiencing the situation which caused the Market Participant to delay the repair of its Generator. The tolling of CRIS rights occurs under this Section 5.18.2.3.2 notwithstanding the three year period in which CRIS-inactive facilities may maintain CRIS rights pursuant to Section 25.9.3.1 of Attachment S to the OATT; provided, however, the expiration period for transfers of CRIS rights provided in Section 25.9.3.1 of Attachment S to the OATT shall not be tolled. A Market Participant seeking to toll its outage and CRIS rights pursuant to this Section 5.18.2.3.2 must submit a Repair Plan no later than 60 days prior to when the

ICAP Ineligible Forced Outage would expire under Section 5.18.2.3.1.

5.18.2.4 A Market Participant with a Generator in an ICAP Ineligible Forced Outage that is notified by a Transmission Owner or the ISO that the return to service of its Generator could address a reliability issue shall provide an updated good faith estimate of the Generator's return date. A Market Participant with a Generator in an ICAP Ineligible Forced Outage shall make a timely return to service to resolve a reliability issue, in accordance with Section 5.18.4, as the term "timely return" is described in Section 5.18.4.2 of this Services Tariff. A Market Participant with a Generator in an ICAP Ineligible Forced Outage shall provide temporary use of its Generator's interconnection point in accordance with Section 5.18.5 of this Services Tariff when a transmission solution using the Generator's interconnection point has been selected as the Short-Term Reliability Process Solution, the Gap Solution, or to resolve a reliability issue arising on a non-New York State Bulk Power Transmission Facility during its outage. The Transmission Owner shall provide that power to the station remains available notwithstanding its temporary use of the Generator's interconnection point.

5.18.3 Mothball Outage

5.18.3.1 Prior to entering a Mothball Outage, the Generator must satisfy the prior notice requirement contained in Section 38.3.1 of Attachment FF to the ISO OATT, among other applicable requirements. A Generator in a Mothball Outage is not eligible to participate in the Installed Capacity market and shall automatically cease to qualify to participate in the Installed Capacity market beginning with the date the Generator begins its Mothball Outage. The Generator shall no longer be ineligible to participate in the Installed Capacity market, by virtue of its Mothball Outage, as of the first day the Generator returns to operation and offers its Energy into the Day-Ahead Market without declaring an outage. The month for which the Generator will first be eligible to participate in the Installed Capacity market will be based on the date the Generator returns to operation and offers its Energy into the Day-Ahead Market without declaring an outage and ISO Procedures.

If one of the two Generators in a CSR enters a Mothball Outage but the other CSR Generator continues operating, the remaining Generator may continue to participate as a Generator in a CSR unless or until the Generator in the Mothball Outage becomes Retired.

5.18.3.2 As part of the Generator Deactivation Notice required prior to entering a Mothball Outage pursuant to Section 38.3.1 of Attachment FF to the ISO OATT, a Market Participant shall notify the ISO whether its Generator will be physically able to return within 180 days to resolve a reliability issue or it has good cause for an alternate period of time, stated in days, to return its Generator to service to resolve a reliability issue. The Market Participant shall establish good cause, to the satisfaction of the ISO, by providing empirical evidence demonstrating the need for the alternate period of time to return its Generator to service to resolve a reliability issue. The number of days within which a Generator in a Mothball Outage can be returned to service to resolve a reliability issue will be shared with the applicable Transmission Owner(s).

5.18.3.3 Mothball Outage Expiration

5.18.3.3.1 Except as provided in Section 5.18.3.3.2, a Generator's Mothball Outage shall expire if: i) its CRIS rights have expired; or ii) it did not have CRIS rights and has been in the Mothball Outage for 36 consecutive months. A Generator shall be Retired if its Mothball Outage expires.

5.18.3.3.2 If a Market Participant with a Generator in a Mothball Outage has Commenced Repair prior to when the Mothball Outage would expire pursuant to Section 5.18.3.3.1 and has provided a reasonable return date as that term is described in Section 5.18.1.2 of this Services Tariff that occurs after such expiration date, then the outage and the Generator's CRIS rights will be tolled until, and the Mothball Outage will expire on, the earlier of: i) 120 days from when the outage would have expired under Section 5.18.3.3.1; or ii) an ISO determination that the Market Participant has ceased or unreasonably delayed the repair of its Generator. The ISO will determine if a Market Participant has unreasonably delayed the repair of its Generator if such delay would not have been included in a Credible Repair Plan from a supplier experiencing the situation which caused the Market Participant to delay the repair of its Generator. The tolling of CRIS rights occurs under this Section 5.18.3.3.2 notwithstanding the three year period in which CRIS-inactive facilities may maintain CRIS rights pursuant to Section 25.9.3.1 of Attachment S to the OATT; provided, however, the expiration period for transfers of CRIS rights provided in Section 25.9.3.1 of Attachment S to the OATT shall not be tolled. A Market Participant seeking to toll its outage and CRIS rights pursuant to this Section 5.18.3.3.2 must submit a Repair Plan no later than 60 days prior to when the Mothball Outage would expire under Section 5.18.3.3.1.

5.18.3.4 A Market Participant with a Generator in a Mothball Outage shall timely return the Generator to service to resolve a reliability issue, in accordance with Section 5.18.4, as the term ‘timely return’ is described in Section 5.18.4.2 of this Services Tariff**.** A Market Participant with a Generator in a Mothball Outage shall provide temporary use of its Generator’s interconnection point, in accordance with Section 5.18.5 of this Services Tariff, when a transmission solution using the Generator’s interconnection point has been selected as the Short-Term Reliability Process Solution, the Gap Solution, or to resolve a reliability issue on a non-New York State Bulk Power Transmission Facility arising during the Generator’s outage. The Transmission Owner shall provide that power to the station remains available notwithstanding its temporary use of the Generator’s interconnection point.

5.18.4 Return to Service of Generators in a Mothball Outage or an ICAP Ineligible Forced Outage to Resolve a Reliability Issue

5.18.4.1 Following: i) notification to a Market Participant that the return to service of its Generator in a Mothball Outage or an ICAP Ineligible Forced Outage for a specified minimum time period has been identified as a Short-Term Reliability Process Solution, a Gap Solution, or to resolve a reliability issue on a non-New York State Bulk Power Transmission Facility arising during the Generator’s outage; and ii) an order establishing compensation for such return from the Federal Energy Regulatory Commission (“Compensation Order”), the Market Participant shall timely return the Generator to service, as the term “timely return” is defined in Section 5.18.4.2 of this Services Tariff.

5.18.4.1.1 Except for Generators selected through the Short-Term Reliability Process, within 30 days of a determination by the ISO and the Market Participant that negotiations on compensation for the return to service of the Market Participant's Generator are at an impasse, the Market Participant may submit a filing to the Federal Energy Regulatory Commission under Section 205 of the Federal Power Act for compensation. No later than ten days after such filing is made, the ISO shall file with the Federal Energy Regulatory Commission an unexecuted compensation agreement that includes the non-rate terms and conditions for the return to service of the Market Participant's Generator.

5.18.4.2 A Market Participant's return to service of its Generator in a Mothball Outage to resolve a reliability issue shall be deemed to be a timely return if such return to service was i**)** within 180 days from the date of the Compensation Order, ii) within the alternate period of time following the date of the Compensation Order pursuant to Section 5.18.3.2, or iii) by such other date agreed to by the parties.

A Market Participant's return to service of its Generator in an ICAP Ineligible Forced Outage to resolve a reliability issue shall be deemed to be a timely return if it is returned to service according to the date established by the Compensation Order; *provided, however,* the Market Participant will not be required to return the Generator to service before its estimated return date unless otherwise agreed.

5.18.4.2.1 A Generator's return to service shall not be untimely if the Generator provided the Transmission Owner with access to its interconnection point and is available for a timely return, and the Transmission Owner is unable to reconnect the Generator within the timeframes provided for a timely return to service, pursuant to Section 5.18.4.2 of this Services Tariff**.**

5.18.5 Temporary Use of Interconnection Point to Resolve a Reliability Issue

5.18.5.1 A Market Participant shall provide a Transmission Owner with temporary use of the interconnection point of its Generator in a Mothball Outage or ICAP Ineligible Forced Outage when a transmission solution using the Generator's interconnection point has been selected as the Short-Term Reliability Process Solution, Gap Solution, or to resolve a reliability issue arising on a non-New York State Bulk Power Transmission Facility during its outage.

5.18.5.2 A Market Participant that provided temporary use of the interconnection point of its Generator in a Mothball Outage or ICAP Ineligible Forced Outage pursuant to Section 5.18.5.1 of this Services Tariff shall be permitted to reconnect its Generator to the transmission system by submitting to the ISO a Notice of Intent to Return that provides the date it intends to return to service which submission shall be provided no later than six months before the expiration of its outage, unless otherwise agreed. A Market Participant that submitted a Notice of Intent to Return and that was not requested to return its Generator to service to resolve a reliability issue pursuant to Section 5.18.4.1 of this Services Tariff during its immediately previous Mothball Outage or ICAP Ineligible Forced Outage, shall be permitted to reconnect at no cost.

The Transmission Owner shall reconnect the Generator on or before the indicated return date using efforts that are timely, consistent with Good Utility

Practice and that are otherwise substantially equivalent to those the Transmission Owner would use for its own purposes. The Transmission Owner shall report periodically to the ISO and the Generator on the progress of reconnecting such Generator and shall advise the ISO and the Generator promptly if it expects it will not be able to complete the reconnection of the Generator before its indicated return date.

If the Generator returning to service pursuant to this Section 5.18.5.2 of the Services Tariff is available to return but the Transmission Owner is unable to reconnect the Generator before its outage expires, the outage expiration, and expiration of its CRIS rights, where applicable, will be tolled until the date the Transmission Owner reconnects the Generator notwithstanding the three year period in which CRIS-inactive facilities may maintain CRIS rights pursuant to Section 25.9.3.1 of Attachment S to the OATT; provided, however, the expiration period for transfers of CRIS rights provided in Section 25.9.3.1 of Attachment S to the OATT shall not be tolled.

5.18.6 Retired and Termination of Existing Interconnection Agreements

The classification of a Generator with an interconnection agreement other than a Small Generator Interconnection Agreement (SGIA) or Standard Large Generator Interconnection Agreement (LGIA) as Retired may be grounds for the termination of the interconnection agreement depending on the terms and conditions of the applicable agreement. Any termination of such an interconnection agreement will be effective on the filing with the Federal Energy Regulatory Commission of a notice of termination, which notice and proposed effective date have been accepted by the Federal Energy Regulatory Commission. Either party to the interconnection agreement may file the notice of termination, as appropriate. If and when termination of the interconnection agreement is effective, access to the Point of Interconnection of the Generator will be available on a non-discriminatory basis pursuant to the NYISO's applicable interconnection and transmission expansion processes and procedures. If the existing interconnection agreement is not terminated, the Retired Generator would retain its right to the specific point of interconnection as provided for in the interconnection agreement and access to this point would not be available for new projects.

The impact on a Generator with a LGIA or SGIA that has been classified as Retired is described in OATT Sections 30 and 32 respectively.

7.2 Billing and Payment Procedures

For purposes of this Section 7.2:

(i) the term “Complete Week Settlement Period” shall mean the seven day period between Saturday and Friday for which all of the days are in the same month; and

(ii) the term “Stub Week Settlement Period” shall mean the six or fewer day period between Saturday and Friday for which all of the days are in the same month.

7.2.1 Billing and Settlement Information

The ISO shall provide settlement and billing information to Customers. The ISO shall inform each Customer that provides or is provided services furnished under this ISO Services Tariff or the ISO OATT of the payments due for such service. Such information shall be made electronically available to the Customer.

7.2.2 Invoicing and Payment

7.2.2.1 Weekly Invoice

On or about each Wednesday, as set forth in ISO Procedures, the ISO shall submit an invoice to a Customer that indicates the net amount owed by or owed to the Customer for those services furnished under this ISO Services Tariff or the ISO OATT for the previous Complete Week Settlement Period or Stub Week Settlement Period that are designated as Weekly Invoice Components in ISO Procedures; *provided, however*, that the net amount owed by or owed to the Customer for those services furnished for a Stub Week Settlement Period that concludes a month shall be included in the next monthly invoice issued in accordance with Section 7.2.2.2 of this ISO Services Tariff.

7.2.2.2 Monthly Invoice

Within five (5) business days after the first day of each month, the ISO shall submit an invoice to a Customer that indicates the net amount owed by or owed to the Customer:

(i) for those services furnished under this ISO Services Tariff or the ISO OATT for a Stub Week Settlement Period that concludes the previous month that are designated as Weekly Invoice Components in ISO Procedures;

(ii) for any adjustments to amounts contained in the weekly invoices issued in the previous month pursuant to Section 7.2.2.1 of this ISO Services Tariff;

(iii) for those services furnished under this ISO Services Tariff or the ISO OATT in the previous month that are designated as Monthly Invoice Components in ISO Procedures;

(iv) for any adjustments to amounts contained in a previously issued monthly invoice that was issued on or about one hundred twenty (120) days prior to the issuance of this invoice; and

(v) for any adjustments to amounts contained in a previously issued monthly invoice as part of the Close-Out Settlement of that monthly invoice pursuant to Section 7.4.1.2 of this ISO Services Tariff.

7.2.2.3 Payment by the Customer

A Customer owing payments on net in its weekly invoice or its monthly invoice shall make those payments to the ISO through the ISO Clearing Account by the second business day after the date on which the weekly invoice or monthly invoice is rendered by the ISO unless otherwise specified in ISO Procedures. In accordance with Section 7.1.2 of this ISO Services

Tariff, the ISO may net any overpayment by the Customer for past estimated charges against current amounts due from the Customer or, if the Customer has no outstanding amounts due, the ISO may pay to the Customer an amount equal to the overpayment.

7.2.2.4 Payment by the ISO

Except as provided in Section 7.1.4 of this ISO Services Tariff, the ISO shall pay all net monies owed to a Customer in its weekly invoice or its monthly invoice from the ISO Clearing Account by the second business day after the due date for Customer payments set forth in Section 7.2.2.3 of this ISO Services Tariff unless otherwise specified in ISO Procedures.

7.2.3 Use of Estimated Data and Meter Data

The ISO may use estimates, including estimated meter data, in whole or in part to settle a weekly or monthly invoice in accordance with ISO Procedures. The ISO shall use meter data submitted to the ISO in accordance with Article 13 of this ISO Services Tariff. Any charges based on estimates shall be subject to true-up in invoices subsequently issued by the ISO after the ISO has obtained the requisite actual information, provided that the ISO shall only true-up charges based on meter data prior to the deadline for finalizing meter data established in Section 7.4 of this ISO Services Tariff. A trued-up charge shall include interest amounts calculated at the rate set forth in Section 7.3 of this ISO Services Tariff from the weekly or monthly due date for the charge until the date of payment of the trued-up amount for that charge.

7.2.4 Method of Payment

All payments by the Customer shall be made by either (i) wire transfer in immediately available funds payable to the ISO through the ISO Clearing Account or (ii) any other method set forth in ISO Procedures. All payments by the ISO shall be made either (i) by wire transfer in immediately available funds payable to the Customer by the ISO through the ISO Clearing Account or (ii) any other method set forth in ISO Procedures.

7.2.5 TCC Auction Settlements

Notwithstanding Sections 7.2.2.1 and 7.2.2.2 of this ISO Services Tariff, the ISO shall make settlements related to the Centralized TCC Auction and the Reconfiguration Auction as set forth in this Section 7.2.5.

7.2.5.1 The ISO shall submit invoices to, and make settlements with, Transmission Owners in connection with the allocation of Net Auction Revenues in accordance with the timeline set forth in ISO Procedures.

7.2.5.2 Customers owing payments to the ISO as a result of their activity in or related to a Centralized TCC Auction or Reconfiguration Auction, pursuant to an award notice or a comparable invoice rendered by the ISO, shall make those payments to the ISO through the ISO Clearing Account in accordance with the timeline set forth in ISO Procedures.

7.2.5.3 Except as provided in Section 7.1.4 of this ISO Service Tariff, the ISO shall pay all net monies owed to Customers as a result of their activity in or related to a Centralized TCC Auction or a Reconfiguration Auction, pursuant to an award notice or a comparable invoice rendered by the ISO, from the ISO Clearing Account in accordance with ISO Procedures.

7.2.5.4 Sections 7.2.1, 7.2.3, 7.2.4, and 7.2.6 of this ISO Services Tariff and Section 19.9.6 of Attachment M of the ISO OATT shall apply to settlements calculated in accordance with this Section 7.2.5.

7.2.6 Verification of Payments

The ISO shall verify that all payments owed by Customers in accordance with this ISO Services Tariff and the ISO OATT have been paid to the ISO in a timely manner. If a Customer fails to make a payment within the time period established in Sections 7.2.2.1, 7.2.2.2, and 7.2.5 of this ISO Services Tariff or pays less than the amount due, the ISO shall take measures pursuant to Section 7.5 of this ISO Services Tariff. Except as provided in Section 7.1.4 of this ISO Services Tariff, the ISO shall also ensure that monies owed to Customers in accordance with this ISO Services Tariff and the ISO OATT are paid through the ISO Clearing Account in a timely manner.

7.2.7 Payments for TSCs

Bills and payments for TSCs shall be issued in accordance with the ISO OATT. Accordingly, this Section 7 shall not apply to TSCs.

7.2.8 Payment for Actual Energy Withdrawals by Energy Storage Resources

A Customer that is participating in the ISO-administered Energy and Ancillary Services markets with an Energy Storage Resource will be subject to Day Ahead Market settlements pursuant to Section 4.2.6 and Real Time Market settlements pursuant to 4.5.2, or in the case of a Supplier of Regulation Service pursuant to Rate Schedule 15.3.6.1 of this ISO Services Tariff. If a Load Serving Entity requires the Energy Storage Resource to also pay a retail rate for its charging withdrawals, then the ISO shall issue a credit to the affected Customer for the associated Actual Energy Withdrawals and assess a charge to this Load Serving Entity for the same Actual Energy Withdrawals. When an Energy Storage Resource participates as a Co-located Storage Resource, the credit issued to an affected Customer and the corresponding charge assessed to the Load Serving Entity will not include the Energy Storage Resource's charging Energy received from the co-located Intermittent Power Resource behind the Co-located Storage Resource’s shared Point of Injection/Point of Withdrawal. The credit and offsetting charge shall be calculated as the product of the Actual Energy Withdrawals of the Energy Storage Resource and the time weighted average Real-Time Market LBMP for the hour at the Energy Storage Resource’s location.

8 Eligibility For ISO Services

In order to participate in any ISO-Administered Market or to be a Primary Holder of a TCC, a Customer must satisfy the applicable requirements of this Article 8 and Attachment K to this Services Tariff, including the minimum participation criteria set forth in Section 26.1 of Attachment K.

8.1 Requirements Common to all Customers

8.1.1 Creditworthiness

All Customers and applicants seeking to become a Customer shall be subject to the creditworthiness requirements contained in Attachment K to this Services Tariff, including the minimum participation criteria set forth in Section 26.1 of Attachment K.

8.1.2 Completed Application and Minimum Technical Requirements

A Customer shall submit a Completed Application in accordance with Article 9 and shall receive ISO approval prior to obtaining any services under the ISO Services Tariff. A Customer also shall demonstrate to the ISO's reasonable satisfaction that it is capable of performing all functions required by the ISO Services Tariff including operational communications, financial and Settlement requirements.

8.1.3 Additional Eligibility Requirements for all Customers

All Customers and applicants seeking to become a Customer shall at all times be:

(a) an "appropriate person," as defined in sections 4(c)(3)(A) through (J) of the Commodity Exchange Act; or

(b) an "eligible contract participant," as defined in section 1a(18)(A) of the Commodity Exchange Act and in 17 CFR 1.3(m); or

(c) a “person who actively participates in the generation, transmission, or distribution of electric energy,” as defined in paragraph 5(g) of the Final Order of the Commodity Futures Trading Commission at 78 FR 19879.

Each Customer must demonstrate compliance with the requirements of this Section 8.1.3 by submitting to the ISO on or before September 15, 2013 an officer’s certificate, in a form acceptable to the ISO, that (i) certifies under penalty of perjury that the Customer is now and will remain in compliance with this requirement, (ii) further certifies that if it no longer satisfies this requirement it shall immediately notify the ISO and immediately cease all participation in the ISO-Administered Markets; (iii) is signed by an authorized officer of Customer, and (iv) is notarized.

Each applicant seeking to become a Customer must demonstrate compliance with the requirements of this Section 8.1.3 by submitting to the ISO with its Completed Application an officer’s certificate, in a form acceptable to the ISO, that (i) certifies under penalty of perjury that the applicant is now and will remain in compliance with this requirement, (ii) further certifies that if it no longer satisfies this requirement it shall immediately notify the ISO and cease all participation in the ISO-Administered Markets (iii) is signed by an authorized officer of applicant, and (iv) is notarized.

In the event a Customer or applicant seeking to become a Customer experiences a change that results in the Customer or applicant no longer satisfying the requirements of this Section 8.1.3, the Customer or applicant shall immediately notify the ISO of this change, and the Customer shall immediately cease all participation in the ISO-Administered Markets.

8.2 Additional Requirements Applicable to Suppliers

In addition to the requirements set forth in Section 8.1 above, Suppliers shall satisfy the communication requirements of Article 4 and the metering requirements of Article 13 prior to entering into a Transaction with the ISO.

Generators that participate in the ISO Administered Markets together as Co-located Storage Resources must share the same bidding entity and the same billing organization. Market Participants and owners of Co-located Storage Resources must provide the ISO at least 60 days advance written notice in order to change the bidding entity or the billing organization for a set of Co-located Storage Resources, and a change of billing organization will only be effectuated on the first day of a month.

8.3 Additional Requirements Applicable to LSEs

In addition to the requirements set forth in Section 8.1 above, each LSE shall satisfy the following requirements prior to taking services under the Tariff:

8.3.1 All requirements and conditions contained within an approved retail access plan in the service territory of the Transmission Owner in which the LSE's Load is located, which retail access plan has been approved by the PSC or other appropriate authority or, in the case of the LIPA, has been approved by the Trustees of the Long Island Power Authority.

8.3.2 All New York State application and license requirements, and any other authorization required by New York State to serve retail Load; and

8.3.3 The LSE must be: (a) aggregating or serving Load that is of an amount greater than or equal to one (1) MW in each hour as measured between a single Point of Injection and a single Point of Withdrawal; or (b) making purchases from the ISO

Administered Markets at a single bus of an amount greater than or equal to one (1) MW in each hour.

8.4 Eligibility to Obtain Services Under This Tariff In Response To Sales Tax Issues

8.4.1 In addition to any other requirements set forth in this Tariff, every Customer and every agent of a Customer ("Agent") seeking to purchase any services under this Tariff shall supply to the ISO and have on file with the ISO at the time the Customer or Agent commences such purchases the following:

8.4.1.1 If the Customer is registered or required to be registered with the New York State Department of Taxation and Finance under Articles 28 and 29 of the New York State Tax Law, or, if the Customer is a non-New York State purchaser, a valid, properly completed New York State exemption document, for example, without limitation, a Resale Certificate, an exempt organization certificate, an exempt purchase certificate or a direct pay permit, issued in accordance with New York State Tax Law; or in the case of a Customer that is a non-New York State purchaser, a written statement of such Customer, sworn to or affirmed under penalties of perjury by the principal executive officer of such Customer, stating its name and address and certifying that the Customer is a non-New York State purchaser, that is not registered or required to be registered with the New York State Department of Taxation and Finance under Articles 28 and 29 of the New York State Tax Law and is not qualified for any New York State Exemption Document, that it makes no purchase of electricity or other tangible personal property or services in markets administered by the ISO for resale or for its own use in New York State and that it makes no retail sales of electricity or other tangible personal property or services in New York State; or

8.4.1.2 If the Customer is not required to register, and is not registered, for sales and compensating use tax purposes under Articles 28 and 29 of the New York State Tax Law, and is not a Customer described in paragraph (A)(3) of this Section 8.4, a valid, properly completed exempt organization certificate issued in accordance with New York State Tax Law; or

8.4.1.3 If the Customer is an entity described in paragraphs one, two or three of subdivision (a) of Section 1116 of the New York State Tax Law, evidence satisfactory under such law that it is such an entity and it is not subject to New York State and local sales and compensating use taxes on its purchases of services under this Tariff; or

8.4.1.4 If the person or entity seeking to make a purchase under this Tariff is an Agent, (a) the appropriate documents described above that its principal would be required to supply and have on file with the ISO if it were making the purchase directly and (b) evidence satisfactory under the New York State Tax Law to establish that person's or entity's status as Agent.

8.4.2 Customer's change in status.

8.4.2.1 If a Customer's certificate of authority issued under Articles 28 and 29 of the New York State Tax Law is revoked, suspended, cancelled, surrendered or otherwise terminated or expires or,

8.4.2.2 If a Customer's status as an exempt organization under New York State Tax Law is revoked, suspended, cancelled, surrendered or otherwise terminated or expires, or, 8.4.2.3 If a Customer is no longer eligible to rely on the exemption document, exempt organization certificate or other satisfactory evidence it furnished to the ISO, that Customer shall immediately notify the ISO of its change in status and shall furnish to the ISO all other information the ISO may require to enable it to comply with its obligations under this Tariff and New York State Tax Law.

8.4.3 Agent's change in status.

8.4.3.1 If an Agent's certificate of authority issued under Articles 28 and 29 of the New York State Tax Law is revoked, suspended, cancelled, surrendered or otherwise terminated or expires or,

8.4.3.2 If an Agent's relationship with a Customer is revoked, suspended, cancelled, surrendered or otherwise terminated or expires, that Agent or former Agent shall immediately notify the ISO of its change in status and shall furnish to the ISO all other information the ISO may require to enable that Agent to comply with its obligations under this Tariff and New York State Tax Law.

8.4.4 Regardless of whether a Customer or its Agent or former Agent notifies the ISO of any change in status, as described in Sections 8.4.2 and 8.4.3 of this Tariff, of either the Customer or of the Agent or former Agent, a change in status, as described in Sections 8.4.2 and 8.4.3 of this Tariff, shall, from the time of its occurrence, be a Default under Section 7.5 of this Tariff and the Customer or Agent, as the case may be, as a Defaulting Party, shall, from the time of that change in status, be required to pay any State and local sales taxes lawfully imposed on its purchases. A Defaulting Party shall have ten days from its change in status to cure the Default and to notify the ISO that it has so cured the Default.

Regardless of whether the ISO has notice of any change in status from the affected Customer, Agent or from a third party, such as the New York State Commissioner of Taxation and Finance, as of the date of Default, the Customer or its Agent on the Customer's behalf shall continue to be allowed to purchase services under this Tariff for ten days from the time that the ISO has actual notice of a change in status.

8.4.5 Immediately upon the ISO receiving notice from a Customer or its Agent described in Sections 8.4.2 and 8.4.3 of this Tariff, or immediately upon learning that a Customer's or its Agent's status has changed as described in Sections 8.4.2 and 8.4.3 of this Tariff, the ISO shall notify the New York State Commissioner of Taxation and Finance of the name, address and federal identifying number of the Customer, and of any Agent of such a Customer, and of the change of status; and the ISO shall keep records of the type, quantity, price, etc. of services any such Customer purchases, or has purchased on its behalf by any Agent, after a change in status; and the ISO shall furnish such information to the Commissioner of Taxation and Finance in such form as the Commissioner requests.

8.4.6 If a Defaulting Party has not cured its Default prior to the expiration of the ten day period described in Section 8.4.4 of this Tariff, in addition to any and all other remedies available under this Tariff or pursuant to law or in equity, the ISO shall have the right to suspend and/or terminate the Defaulting Party's Service Agreement immediately upon notice to the Commission.

13 Metering

13.1 General Requirements

Existing metering in the NYCA provides revenue-quality metering information among the currently designated electrical zones separated by the designated transmission Interfaces. In addition, sufficient metering information will be made available by the ISO to calculate Load for the individual Transmission Owners within each Load Zone. The ISO will require adequate metering for all Generators, Co-located Storage Resources, and Loads within the NYCA to ensure the reliable operation of the NYS Power System.

13.2 Requirements Pertaining to Customers

Customers shall provide to the ISO such information and data as the ISO reasonably deems necessary in order to perform its functions and fulfill its responsibilities under the ISO Services Tariff and in accordance with the ISO Market Power Monitoring Program. Such information will be provided on a timely basis and in the formats prescribed in the ISO Procedures. The ISO shall establish metering and real-time telemetry specifications and standards for all metering and telemetry used by the ISO, which specifications and standards will be set forth in ISO Procedures. Customers shall install and maintain metering and telemetry hardware and infrastructure at their own expense, and deliver data to the ISO without charge.

A Customer taking service under the ISO Services Tariff will make available to the ISO metered data that meets ISO requirements by one of the following means: (i) direct transmission to the ISO; (ii) direct transmission to the ISO through Transmission Owner communications equipment, or (iii) indirectly through metering provided by the Transmission Owner in whose Load Zone it is located.

Customers shall provide real-time telemetry for Generators and Co-located Storage Resources, nominally every six (6) seconds, in accordance with the specifications set forth in the ISO Procedures. Real-time telemetry data errors and transmission disruptions shall be remedied in accordance with ISO Procedures.

The Customer also shall provide its metered data to the Transmission Owner in whose Load Zone it is located, to the extent that the Transmission Owner determines that the metered data provided to the ISO is required for its system operation and planning functions, for the billing of services it provides to the Customer, or to perform calculations required as part of the ISO Settlement procedures.

13.2.1 Load Serving Entities

Any Load that is not directly metered, as described above, will have its Load determined by the Transmission Owner in whose Load Zone it is located in accordance with the Transmission Owner's retail access plan on file with the PSC or otherwise authorized.

13.2.2 Ancillary Service Suppliers

Suppliers shall ensure that adequate metering data is made available to the ISO as described above. Additionally, for operational purposes, metered data provided to the ISO must also simultaneously be provided to the Transmission Owner, which will handle such information in conformity with the OASIS standards of conduct as specified in Order No. 889.

13.2.3 Estimation of Metering

In the event of a meter malfunction or inadequate metering data, the ISO may use estimates to determine Customer's rights and responsibilities under the ISO Services Tariff.

13.2.4 Energy Storage Resources

In addition to the metering requirements applicable to Energy Storage Resources because they are Generators, specific metering rules apply to account for Energy injections and withdrawals.

13.2.4.1 An Energy Storage Resource, including an Energy Storage Resource that is electrically located behind the same point of interconnection as a load facility or other Resource, must separately and directly meter Energy injections and withdrawals of the Energy Storage Resource. Such metering must allow the Meter Authority and/or ISO is able to distinguish the Energy injections and withdrawals of the Energy Storage Resource from all other injections and withdrawals behind the point of interconnection.

13.2.4.2 Hourly meter data for Energy Storage Resources shall be reported as two separate components: (i) Energy injections, and (ii) Energy withdrawals. Each component shall be submitted to the NYISO by the Meter Authority in separate fields such that the ISO is able to separately determine the total Energy injections and withdrawals in each interval.

13.2.4.3 If an Energy Storage Resource is electrically located behind the same point of interconnection as a load facility, the Meter Authority shall submit to the ISO (i) directly metered Energy injection and withdrawal data (pursuant to Services Tariff § 13.2.4.2), and (ii) the Load (excluding the Energy injections and withdrawals of the Energy Storage Resource) of the co-located facility behind the point of interconnection (pursuant to OATT § 2.7.4.2.1 (ii) & (iv)).

The ISO Procedures, including the Revenue Meter Requirements Manual (M-25), Control Center Requirements Manual (M-21), and Accounting and Billing Manual (M-14) contain additional information related to metering requirements for Generators and Energy Storage Resources.

13.3 Metering Requirements for Demand Side Resources

13.3.1 Responsibility for Metering and Meter Data Services for Aggregations and Demand Side Resources

13.3.1.1 An Aggregator, Demand Reduction Provider, DSASP Provider, Responsible Interface Party, or Curtailment Service Provider shall obtain metering and meter data services, as these services are defined in ISO Procedures, from: (i) the Member System in which Transmission District the Aggregation or Demand Side Resource is located, and/or (ii) an authorized Meter Services Entity that the ISO has determined complies with the eligibility requirements pursuant to Section 13.3.2.1. A Demand Reduction Provider, DSASP Provider, Responsible Interface Party, or Curtailment Service Provider that meets the eligibility requirements in Section 13.3.2.1 may serve as its own Meter Services Entity.

13.3.1.2 The Demand Reduction Provider, DSASP Provider, Responsible Interface Party or Curtailment Service Provider shall be responsible for ensuring that all of the metering and meter data services that are required for it to perform its functions and fulfill its responsibilities under the ISO Tariffs and ISO Procedures are provided by the Member System and/or Meter Services Entity in accordance with the requirements in this Section 13 and ISO Procedures. The Demand Reduction Provider, DSASP Provider, Responsible Interface Party, or Curtailment Service Provider shall be responsible for any applicable penalties issued as a result of metering or meter data services that do not comply with the

ISO Tariffs and ISO Procedures, including, but not limited to, penalties issued pursuant to Services Tariff Sections 5.12 and 5.14.

13.3.1.3 A Demand Reduction Provider, DSASP Provider, Responsible Interface Party, or Curtailment Service Provider shall be responsible for any required compensation to the Member System and/or Meter Services Entity concerning the provision of metering and/or meter data services. In accordance with Services Tariff Section 15.10 (Rate Schedule 10), Demand Reduction Provider, DSASP Provider, Responsible Interface Parties and Curtailment Service Providers shall be responsible for the ISO's costs of conducting audits pursuant to Section 13.3.2.3.

13.3.2 Meter Services Entity Requirements

13.3.2.1 Eligibility Determination for Meter Services Entity

To be authorized as a Meter Services Entity, an entity must complete, to the NYISO's satisfaction, the application requirements specified in Services Tariff Section 13.3.2.1.2 below. Once authorized, a Meter Services Entity must meet the obligations set forth in Services Tariff Sections 13.3.2.1.3 and 13.3.2.1.4. All physical metering infrastructure and meter data communications infrastructure used by a Meter Services Entity must comply with the requirements set forth in the ISO Tariffs and ISO Procedures.

13.3.2.1.1 An entity, including a Demand Reduction Provider, DSASP Provider, Responsible Interface Party, or Curtailment Service Provider, seeking to be a Meter Services Entity must submit to the ISO an application containing the eligibility information required pursuant to Section 13.3.2.1.2, accompanied by a non-refundable application fee of $1,000. The ISO shall review the application within thirty (30) calendar days of its receipt of the application and fee, and notify the applicant whether the application is sufficient to register the applicant as a Meter Services Entity or otherwise requires additional information. Any additional information required shall be received by the ISO within the timeframe specified by the ISO in its request for additional information. The ISO shall reject the application of an entity seeking to become a Meter Services Entity if the required information is not received within the specified timeframe or an alternative, mutually agreed to timeframe.

Upon the ISO's affirmative determination of an entity's eligibility, the entity will be registered with the ISO and authorized to serve as a Meter Services Entity in order to provide metering and/or meter data services, as applicable, to a Demand Reduction Provider, DSASP Provider, Responsible Interface Party, or Curtailment Service Provider. The ISO shall post on its website a list of all authorized Meter Services Entities.

If the ISO determines an entity is not eligible to serve as a Meter Services Entity, the ISO shall provide the entity with the reasons for such determination. An entity that seeks to re-apply to be a Meter Services Entity shall also be required to pay the $1,000 application fee.

13.3.2.1.2 An entity seeking to be a Meter Services Entity must provide, at a minimum, the following eligibility information, as detailed in ISO Procedures: (i) financial eligibility and insurance coverage information; (ii) proof of eligibility to do business in New York State; (iii) a list of the Transmission Owner(s) service territory(ies) in which it will provide services; (iv) a description of the metering and/or meter data services that it will provide; (v) its attestation of its employees' qualifications, training, and certification to perform the listed services; (vi) a description of the meter testing laboratory facilities, including its attestation that its meter testing programs comply with ISO Procedures and Good Utility Practice; (vii) its agreement that its services will be subject to audit by the ISO, the Transmission Owners, and/or their designated agents, as applicable; (viii) its agreement to comply with the metering requirements in the ISO Tariffs and ISO Procedures, as such requirements may be amended from time to time; (ix) a revenue-grade settlement meter and real-time telemetry data plan; (x) a meter data validation, editing, and estimation plan; (xi) a security plan and description of how it will protect meter equipment and/or meter data from unauthorized physical or electronic entry or tampering; (xii) a description of how and where records of meter installations and/or meter data will be kept, and its agreement to retain these records in accordance with the ISO's recordkeeping requirements; and (xiii) any other information required by ISO Procedures or requested by the ISO.

13.3.2.1.3 A Meter Services Entity shall promptly inform the ISO, in accordance with ISO procedures, of any material change to the eligibility information it has previously submitted to the ISO pursuant to Section 13.3.2.1.2. The ISO shall review all such material changes and determine whether the Meter Services Entity complies with all eligibility requirements. If the NYISO determines that the Meter Services Entity does not comply with the eligibility requirements, it may suspend the Meter Services Entity's eligibility until such time that it complies with those eligibility requirements.

13.3.2.1.4 The ISO shall inform registered Meter Services Entities of changes related to Meter Services Entity eligibility requirements via posting to the ISO's public website and electronic mail. A Meter Services Entity has a continuing obligation to comply with the eligibility requirements in this Section 13 and ISO Procedures and the metering and meter data requirements in the ISO Tariffs and ISO Procedures, as the requirements may be amended from time to time. Each Meter Services Entity shall inform the ISO, in accordance with ISO Procedures, and received by the date specified in the ISO's posting, of its compliance with the identified changes to eligibility criteria. If the Meter Services Entity is unable to comply with the changes by the specified date, it shall provide the ISO with a detailed plan to comply. The ISO shall review all such plans and determine whether to extend the compliance deadline, or to suspend the Meter Services Entity's eligibility until such time that it complies with all eligibility requirements.

13.3.2.2 Standards of Conduct for Meter Services Entities

A Meter Services Entity must treat all customers, Affiliated and non-Affiliated, on a non-discriminatory basis, and must not make or grant any undue preference or advantage to any person or subject any person to any undue prejudice or disadvantage with respect to the provision of metering services authorized by Services Tariff Section 13.3.

13.3.2.3 ISO Audits and Corrective Actions

13.3.2.3.1 The ISO or its designated entity may, upon reasonable notice, perform an audit, inspection, and/or test of the Meter Services Entity's metering facilities, meters, and/or meter data records to ensure they comply with the ISO Tariffs and ISO Procedures and with the Meter Services Entity's plans submitted to the ISO. Meter Services Entities must comply with, i) periodic audits of meter data records and meter data collection and retention services and protocols provided to the

Market Participant by the Meter Services Entity; and ii) audits of the metering facilities, meter data records and meter data collection and retention services and protocols utilized by the Market Participant and the Meter Services Entity when the Market Participant enrolls new resources or modifies the metering scheme of existing resources.

The ISO's audit of a MSE's services may involve, but is not limited to, the ISO's review, inspection, performance testing and review of corrective actions taken in the following categories:

A) Validation, Estimation, & Editing (VEE) methodology;

B) Site meter configurations;

C) Meter compliance with ISO rules and procedures;

D) Meter Services Entity operational protocols, procedures, and record keeping, and compliance with ISO rules and procedures; and

E) Telemetry and communication data and records.

13.3.2.3.2 If the ISO determines, at any time, that a Meter Services Entity does not comply with the eligibility requirements or does not comply with the metering or meter data requirements set forth in the ISO Tariffs and ISO Procedures, the ISO may suspend or revoke the eligibility of the Meter Services Entity.

15.2 Rate Schedule 2 - Payments for Supplying Voltage Support Service

This Rate Schedule applies to payments to Suppliers who provide Voltage Support Service to the ISO. Transmission Customers and Customers will purchase Voltage Support Service from the ISO under the ISO OATT.

Suppliers provide Voltage Support Service from eligible providers, which are Generators with an automatic voltage controlling equipment ("Generators," for the purpose of this Rate Schedule 2), synchronous condensers, and Qualified Non-Generator Voltage Support Resources. Qualified Suppliers of Voltage Support Service shall be referred to as such or as Voltage Support Resources in this Rate Schedule. An RMR Generator operating under an RMR Agreement that provided Voltage Support Service at any time during the most recent twelve (12) months that it participated in the ISO Administered Markets must provide Voltage Support Service during the term of its RMR Agreement, unless it demonstrates to the ISO's satisfaction that it is no longer capable of providing the service. An Interim Service Provider that is required to keep its generating units in service and that provided Voltage Support Service during the most recent twelve (12) months that it participated in the ISO Administered Markets must continue to provide Voltage Support Service, unless it demonstrates to the ISO's satisfaction that it is no longer capable of providing the service. The rate provided in this Rate Schedule shall be used to calculate payments to eligible Suppliers providing Voltage Support Service as applied on a technology-specific basis. The ISO shall calculate payments on an annual basis, and make payments monthly.

15.2.1 Responsibilities

The ISO shall coordinate the Voltage Support Service provided by Suppliers that qualify to provide such services as described in Section 15.2.1.1 of this Rate Schedule 2. The ISO shall also establish methods and procedures for Reactive Power (MVAr) capability testing.

15.2.1.1 Suppliers

To qualify for payments, Suppliers of Voltage Support Service shall provide a Generator that has automatic voltage controlling equipment, or a Qualified Non-Generator Voltage Support Resource with automatic voltage controlling equipment, other than the Cross Sound Scheduled Line, or a synchronous condenser, each of which must be electrically located within the NYCA. Automatic voltage controlling equipment includes but is not limited to an Automatic Voltage Regulator ("AVR") for non-inverter-based Generators or inverters capable of automatic voltage control for inverter-based Generators. All Suppliers of Voltage Support Service must successfully perform Reactive Power (MVAr) capability testing in accordance with the ISO Procedures and prevailing industry standards. The ISO may direct Qualified Suppliers of Voltage Support Service to operate their Voltage Support resources within these demonstrated reactive capability limits. Qualified Suppliers of Voltage Support Service will test their Voltage Support Resources and provide these services in accordance with ISO Procedures.

Voltage Support Service includes the ability to produce or absorb Reactive Power within the Voltage Support Resource's tested reactive capability, and the ability to maintain a specific voltage level under both steady-state and post-contingency operating conditions subject to the limitations of the Voltage Support Resource's stated reactive capability. The requirement for a Voltage Support Resource to absorb Reactive Power may be set aside by the ISO with input from the Transmission Owner in whose Transmission District the Voltage Support Resource is located, which input may include, at the Transmission Owner's option, an executive level review. To grant an exemption from the requirement that the Voltage Support Resource be able to absorb Reactive Power, the ISO shall have determined that: 1) the Voltage Support Resource is unable, due to transmission system configuration, to absorb Reactive Power; 2) the ability of the Voltage Support Resource to produce Reactive Power is needed for system reliability; and 3) for purposes of system reliability the Voltage Support Resource does not need to have the ability to absorb Reactive Power.

An RMR Generator that is required to provide Voltage Support Service must timely perform the annual testing applicable to all Suppliers of Voltage Support Service described in this Section 15.2.1 and in ISO Procedures so that it remains continuously eligible to provide Voltage Support Service during the term of its RMR Agreement. If such an RMR Generator did not timely perform all of the annual testing required for it to provide Voltage Support Service prior to the start of the term of its RMR Agreement, then the ISO shall permit the RMR Generator to perform Reactive Power (MVAr) capability testing in accordance with the ISO Procedures upon entering the RMR Agreement and shall permit the RMR Generator to be a Qualified Supplier of Voltage Support Service. An Interim Service Provider that is required to keep its generating units in service must timely perform the annual testing applicable to all Suppliers of Voltage Support Service described in this Section 15.2.1 and in ISO Procedures so that it remains continuously eligible to provide Voltage Support Service. If such an Interim Service Provider did not timely perform all of the annual testing required for it to provide Voltage Support Service, then the ISO shall permit the Interim Service Provider to perform Reactive Power (MVAr) capability testing in accordance with the ISO Procedures promptly upon becoming an Interim Service Provider and shall permit the Interim Service Provider to be a Qualified Supplier of Voltage Support Service.

15.2.2 Payments

Each month, Suppliers whose Generator(s) meet the requirements to supply Installed Capacity, as described in Article 5 of the ISO Services Tariff, and are under contract to supply Installed Capacity, shall receive one-twelfth (1/12th) of the annual payment calculated under Section 15.2.2.1 of this Rate Schedule for Voltage Support Service.

Each month, Suppliers whose Generators are not under contract to supply Installed Capacity, Suppliers with synchronous condensers, and, except as noted in the following paragraph, Qualified Non-Generator Voltage Support Resources shall receive one-twelfth (1/12th) of the annual payment calculated under Section 15.2.2.1 of this Rate Schedule , pro-rated by the number of hours that the Generator, synchronous condenser, or Qualified Non-Generator Voltage Support Resource operated in that month, as recorded by the ISO.

Each month, the Cross-Sound Scheduled Line shall receive one-twelfth (1/12th) of the annual payment calculated under Section 15.2.2.1 of this Rate Schedule, pro-rated by the number of hours that it is energized in that month, as recorded by the ISO.

15.2.2.1 Annual Payment for Voltage Support Service

For purposes of the calculation set forth in Section 15.2.2 of this Rate Schedule, the annual payment to Suppliers qualified and eligible to provide Voltage Support Service shall equal the product of the VSS Compensation Rate and the sum of the lagging and the absolute value of the leading MVAr capacity of the resource, as evidenced by tests conducted pursuant to ISO Procedures.

For VSS Suppliers that are CSR Generators, compensation for each VSS Supplier shall be limited to the lesser of its Reactive Power capability, demonstrated in accordance with ISO procedures, or the total Reactive Power capability at the CSR's Point of Injection/Point of Withdrawal.

The VSS Compensation Rate of $2,592/MVAr, as determined in 2014, shall be adjusted annually by the annual average Consumer Price Index of the previous year.

15.2.2.2 Lost Opportunity Costs

A Supplier of Voltage Support Service from a Generator that is being dispatched by the ISO shall also receive a payment for Lost Opportunity Costs ("LOC") when the ISO directs the Generator to reduce its real power (MW) output below its Economic Operating Point in order to allow the Generator to produce or absorb more Reactive Power (MVAr), unless the Supplier is already receiving a Day-Ahead Margin Assurance Payment for that reduction under Attachment J to this ISO Services Tariff. The Lost Opportunity Cost payment shall be calculated as the maximum of zero or the difference between: (i) the product of: (a) the appropriate MW of output reduction and (b) the Real-Time LBMP at the Generator bus; and (ii) the Generator's Energy Bid for the reduced output of the Generator multiplied by the time duration of reduction in hours or fractions thereof.

The formula below describes the calculation of LOC as applied to each Generator supplying Voltage Support Service.

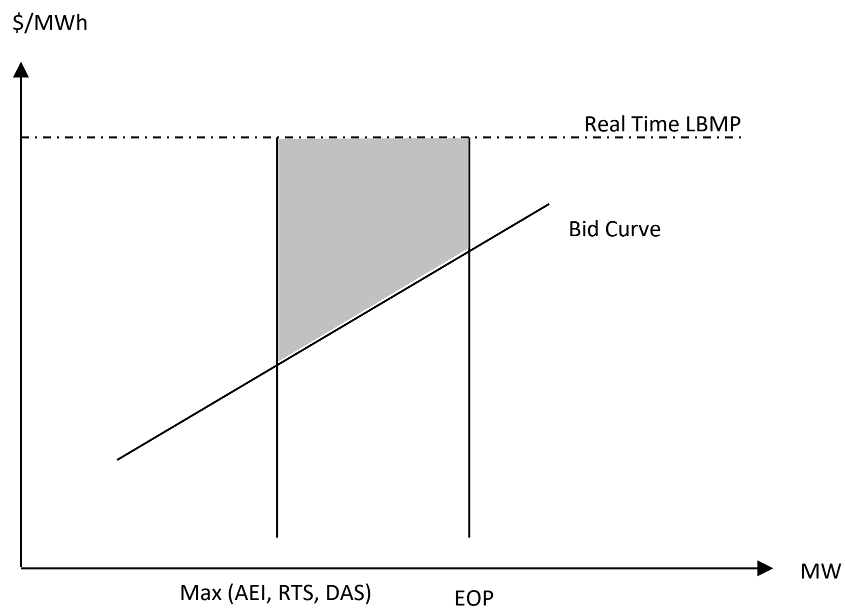
$$LOC_i = max\left(\left(LBMP_{RT,i} * \left(EOP_i - max(AEI_i, RTS_i, DAS_i)\right) - \int_{max(AEI_i, RTS_i, DAS_i)}^{EOP_i} Bid\right), 0\right) * \frac{S_i}{3600}$$

Where:

LOC_i	=	Lost Opportunity Cost for interval *i*
$LBMP_{RT,i}$	=	Real-time LBMP for interval *i*
EOP_i	=	The Generator's Economic Operating Point for interval *i*
AEI_i	=	The Generator's Actual Energy Injection for the interval *i*
RTS_i	=	The Generator's Real-Time Energy Schedule for interval *i*
DAS_i	=	The Generator's Day-Ahead Schedule for the hour containing *i*
Bid_i	=	Generator's Bid curve in effect for interval *i*
$S_i/3600$	=	The length of interval *i*, containing $S_i^{seconds}$ in units of hours

Figure 2.0(b) below graphically portrays the calculation of the LOC for a Generator which reduced its MW output to allow it to produce or absorb more Reactive Power (MVAr).

Figure 2.0(b) - Incremental Bid Curve Used to Calculate LOC



15.2.2.3 Other Payments to Synchronous Condensers and Qualified Non-Generator Voltage Support Resources

If a synchronous condenser or Qualified Non-Generator Voltage Support Resource energizes in order to provide Voltage Support Service in response to a request from the ISO, the

ISO shall compensate the facility for the cost of Energy it consumes to energize converters and other equipment necessary to provide that Voltage Support Service.

15.2.3 Failure to Perform by Suppliers

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

15.2.3.1 when operating at real-power levels consistent with test conditions, fails within ten minutes to be within 5% (+/-) of the requested Reactive Power (MVAr) level of production or absorption as requested by the ISO or applicable Transmission Owner unless it was prevented from doing so by transmission system conditions and except when the Voltage Support Resource is requested not to produce or absorb Reactive Power in which case that Voltage Support Resource fails to provide Voltage Support if the absolute value of its level of Reactive Power production or absorption within ten minutes is greater than 5% multiplied by the sum of the absolute values of (a) that Voltage Support Resource's maximum reactive power production level under test conditions and (b) that Voltage Support Resource's maximum reactive power absorption level under test conditions;

15.2.3.2 when operating at real-power levels consistent with test conditions, fails within ten minutes to be at 95% or greater of the Voltage Support Resource's demonstrated Reactive Power capability (tested pursuant to ISO Procedures) in the appropriate lead or lag direction when requested to go to maximum lead or lag reactive capability by the ISO or applicable Transmission Owner unless it was prevented from doing so by transmission system conditions;

15.2.3.3 fails to provide Voltage Support Service in a Contingency, as defined by ISO Procedures;

15.2.3.4 fails to maintain its automatic voltage controlling equipment (as appropriate) in service and in automatic voltage control mode, or fails to commence timely repairs to the automatic voltage controlling equipment.

Suppliers of Voltage Support Service that fail to comply with the ISO Procedures will be assessed charges by the ISO in the manner described in Sections 15.2.4, 15.2.5, and 15.2.6 below.

15.2.4 Failure to Respond to ISO's Request for Steady-State Voltage Control

Failure: If a Voltage Support Resource fails to comply with the ISO's request for steady-state voltage control, the ISO shall withhold Voltage Support Service payments from the non-complying Supplier equivalent to the VSS Failure to Perform Penalty for that specific Generator, synchronous condenser, or Qualified Non-Generator Voltage Support Resource for that month. The Supplier shall also be liable for any additional cost in procuring replacement Voltage Support Service including LOC incurred by the ISO as a direct result of the Supplier's non-performance.

The formula below describes the monthly VSS Failure to Perform Penalty (VFP)

$$VFP = (VSS\ payment\ for\ the\ month) * (F/R)$$

Where:

F = number of failures in the month

R = number of times the Voltage Support Resource was called upon for Voltage Support in the month

Repeated Failures: In addition to the charges for failure, the non-complying Supplier will also be subject to the charges described in this paragraph. If a Supplier’s Voltage Support Resource fails to comply with fifty percent (50%) or more of the ISO's requests for two consecutive months, then the non-complying Supplier will no longer be eligible for Voltage Support Service payments for service provided by that Voltage Support Resource. The ISO may reinstate payments once the Supplier complies with the following conditions to the ISO's satisfaction:

15.2.4.1 the Supplier's Voltage Support Resource must successfully perform a Reactive Power (MVAr) capability test, and

15.2.4.2 the Supplier’s Voltage Support Resource must provide Voltage Support Service for thirty (30) consecutive days without any compliance failures. No payments for Voltage Support Service or LOC will be made to the Supplier on account of Voltage Support Service from such Voltage Support Resource during this period.

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

If a Supplier's Voltage Support Resource fails to respond to a contingency, based on ISO review and analysis, the ISO shall withhold Voltage Support Service payments from the non-complying Supplier as follows:

Initial Failure: The ISO will withhold from the Supplier one-twelfth (1/12th) of the annual payment for the specific 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).

Second Failure within the same thirty (30) day period: The ISO shall withhold from the Supplier one-fourth (1/4th) of the annual payment for the specific 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). In addition, the Supplier that is in violation shall be prohibited from receiving Voltage Support Service payments for the non-complying Voltage Support Resource until the Supplier complies with the following conditions to the ISO's satisfaction:

15.2.5.1 the Supplier's Voltage Support Resource shall successfully perform a Reactive Power (MVAr) capability test, and

15.2.5.2 the Supplier's Generator, synchronous condenser, or Qualified Non-Generator Voltage Support Resource shall provide Voltage Support Service for thirty (30) consecutive days without any compliance failures. No payments for Voltage Support Service, or LOC shall be made to the Supplier on account of Voltage Support Service from such Generator, synchronous condenser, or Qualified Non-Generator Voltage Support Resource during this period.

15.2.6 Failure to Maintain Automatic Voltage Controlling Equipment or Commence Timely Repairs

If a Supplier's Voltage Support Resource, other than the Cross Sound Scheduled Line, fails to maintain its automatic voltage controlling equipment and fails to notify the ISO, in accordance with ISO procedures, of an outage lasting more than thirty (30) days the Voltage Support Resource will be disqualified as a supplier of Voltage Support Service.

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

(1) the Supplier provides documentation to the NYISO of the completion of the repairs;

(2) the Supplier's Voltage Support Resource successfully performs a Reactive Power (MVAr) capability test, and;

(3) the Supplier's Voltage Support Resource provides Voltage Support Service for thirty (30) consecutive days without any compliance failures. No payments for Voltage Support Service or LOC on account of Voltage Support Service from such Generator or Qualified Non-Generator Voltage Support Resource shall be made to the Supplier during this period.

If, in accordance with ISO procedures, a Qualified Supplier of Voltage Support Service notifies the ISO within thirty days of an automatic voltage controlling equipment outage that lasts longer than thirty days, but the Supplier fails to commence timely and appropriate repairs, the Voltage Support Resource will remain in the VSS program and will receive one half its full monthly VSS payment. The Voltage Support Resource will begin receiving full monthly VSS payment when its automatic voltage controlling equipment returns to full functionality. The Voltage Support Resource will not be eligible for VSS payment in the next compensation year if it fails to repair its automatic voltage controlling equipment and perform an acceptable test in accordance with ISO procedures.

15.2.7 Consistence with Cross-Sound Scheduled Line Protocols

Nothing in this Rate Schedule shall be construed to change existing protocols between the ISO and ISO New England, Inc. regarding the operation of the Cross-Sound Scheduled Line.

15.4 Rate Schedule 4 - Payments for Supplying Operating Reserves

This Rate Schedule applies to payments to Suppliers that provide Operating Reserves to the ISO. Transmission Customers will purchase Operating Reserves from the ISO under Rate Schedule 5 of the ISO OATT.

15.4.1 General Responsibilities and Requirements

15.4.1.1 ISO Responsibilities

The ISO shall procure on behalf of its Customers a sufficient quantity of Operating Reserve products to comply with the Reliability Rules and with other applicable reliability standards, as well as Scarcity Reserve Requirements. These quantities shall be established under Section 15.4.7 of this Rate Schedule for locational Operating Reserve requirements and Section 15.4.6.2 of this Rate Schedule for Scarcity Reserve Requirements. To the extent that the ISO enters into Operating Reserve sharing agreements with neighboring Control Areas its Operating Reserves requirements shall be adjusted as, and where, appropriate.

The ISO shall define requirements for Spinning Reserve, which may be met only by Suppliers that are eligible, under Section 15.4.1.2 of this Rate Schedule, to provide Spinning Reserve; 10-Minute Reserve, which may be met by Suppliers that are eligible to provide either Spinning Reserve or 10-Minute Non-Synchronized Reserve; and 30-Minute Reserve, which may be met by Suppliers that are eligible to provide any Operating Reserve product. The ISO shall also define locational requirements for Spinning Reserve, 10-Minute Reserve, and 30-Minute Reserve located East of Central-East, in Southeastern New York, in New York City, and on Long Island. In addition to being subject to the preceding limitations on Suppliers that can meet each of these requirements, the requirements for Operating Reserve located East of Central-East may only be met by eligible Suppliers that are located East of Central-East, requirements for

Operating Reserve located in Southeastern New York may only be met by eligible Suppliers that are located in Southeastern New York, requirements for Operating Reserve located in New York City may only be met by eligible Suppliers that are located in New York City, and requirements for Operating Reserve located on Long Island may only be met by eligible Suppliers located on Long Island. Each of these Operating Reserve requirements shall be defined consistent with the Reliability Rules and other applicable reliability standards. The ISO shall also establish Scarcity Reserve Requirements in the Real-Time Market pursuant to Section 15.4.6.2 of this Rate Schedule, which may be met by Suppliers eligible to provide 30-Minute Reserve. Scarcity Reserve Requirements may only be met by eligible Suppliers that are located in the Scarcity Reserve Region associated with a given Scarcity Reserve Requirement. The ISO shall select Suppliers of Operating Reserves products to meet these requirements, including the locational Operating Reserves requirements and Scarcity Reserve Requirements, as part of its overall co-optimization process.

The ISO shall select Operating Reserves Suppliers that are properly located electrically so that all locational Operating Reserves requirements determined consistently with the requirements of Section 15.4.7 of this Rate Schedule and Scarcity Reserve Requirements determined consistently with the requirements of Section 15.4.6.2 of this Rate Schedule are satisfied, and so that transmission Constraints resulting from either the commitment or dispatch of Generators do not limit the ISO’s ability to deliver Energy to Loads in the case of a Contingency. The ISO will ensure that Suppliers that are compensated for using Capacity to provide one Operating Reserve product are not simultaneously compensated for providing another Operating Reserve product, or Regulation Service, using the same Capacity (consistent with the additive market clearing price calculation formulae in Sections 15.4.5.1 and 15.4.6.1 of this Rate Schedule).

15.4.1.2 Supplier Eligibility Criteria

The ISO shall enforce the following criteria, which define which types of Suppliers are eligible to supply particular Operating Reserve products.

15.4.1.2.1 Spinning Reserve:

Suppliers that are ISO Committed Flexible or Self-Committed Flexible, are operating within the dispatchable portion of their operating range, are capable of responding to ISO instructions to change their output level within ten minutes, and that meet the criteria set forth in the ISO Procedures shall be eligible to supply Spinning Reserve (except for Demand Side Resources that are Local Generators not utilizing inverter-based energy storage technology and Behind-the-Meter Net Generation Resources that are comprised of more than one generating unit and dispatched as a single aggregate unit). Suppliers utilizing inverter-based energy storage technology, and that meet the criteria set forth in the ISO Procedures, shall be eligible to supply Spinning Reserve when withdrawing or injecting Energy, and when idle.

15.4.1.2.2 10-Minute Non-Synchronized Reserve:

(i) Off-line Generators that are capable of starting, synchronizing, and increasing their output level within ten (10) minutes; (ii) Behind-the-Meter Net Generation Resources that are comprised of more than one generating unit and dispatched as a single aggregate unit that are capable of increasing their output level within ten (10) minutes; and (iii) Demand Side Resources that are capable of reducing their Energy usage within ten (10) minutes, that meet the criteria set forth in the ISO Procedures shall be eligible to supply 10-Minute Non-Synchronized Reserve.

15.4.1.2.3 30-Minute Reserve:

(i) Generators, except Behind-the-Meter Net Generation Resources that are comprised of more than one generating unit and dispatched as a single aggregate unit, that are ISO-Committed Flexible or Self-Committed Flexible and operating within the dispatchable portion of their operating range and Demand Side Resources that do not facilitate demand reduction using Local Generators, or that facilitate demand reduction using a Local Generator utilizing inverter-based energy storage technology, that are capable of reducing their Energy usage within thirty (30) minutes shall be eligible to supply synchronized 30-Minute Reserves. Suppliers utilizing inverter-based energy storage technology, and that meet the criteria set forth in the ISO Procedures, shall be eligible to supply synchronized 30-Minute Reserves when withdrawing or when injecting Energy, and when idle; (ii) Off-line Generators that are capable of starting, synchronizing, and increasing their output level within thirty (30) minutes; (iii) Behind-the-Meter Net Generation Resources that are comprised of more than one generating unit and dispatched as a single aggregate unit that are capable of increasing their output level within thirty (30) minutes; and (iv) Demand Side Resources that are capable of reducing their Energy usage within thirty (30) minutes, that meet the criteria set forth in the ISO Procedures shall be eligible to supply non-synchronized 30-Minute Reserves.

15.4.1.2.4 Self-Committed Fixed and ISO-Committed Fixed Generators:

Shall not be eligible to provide any kind of Operating Reserve.

15.4.1.3 Other Supplier Requirements

All Suppliers of Operating Reserve must be located within the NYCA and must be under ISO Operational Control. Each Supplier bidding to supply Operating Reserve or reduce demand must be able to provide Energy or reduce demand consistent with the Reliability Rules and the ISO Procedures when called upon by the ISO.

All Suppliers that are selected to provide Operating Reserves shall ensure that their Resources maintain and deliver the appropriate quantity of Energy, or reduce the appropriate quantity of demand, when called upon by the ISO during any interval in which they have been selected.

Generators or Demand Side Resources that are selected to provide Operating Reserve in the Day-Ahead Market or any supplemental commitment may increase their Incremental Energy Bids or Demand Reduction Bids, respectively, for portions of their Resources that have been scheduled through those processes; provided however, that they are not otherwise prohibited from doing so pursuant to other provisions of the ISO's Tariffs. Withdrawal-Eligible Generators that are scheduled to withdraw Energy, and that are selected to provide Operating Reserve in the Day-Ahead Market or any supplemental commitment, may decrease their Bids to withdraw Energy for portions of their resources that have been scheduled through those processes; provided however, that they are not otherwise prohibited from doing so pursuant to other provisions of the ISO's Tariffs. Generators or Demand Side Resources that are selected to provide Operating Reserve in the Day-Ahead Market or any supplemental commitment may not, however, reduce their Day-Ahead Market or supplemental commitments in real-time except to the extent that they are directed to do so by the ISO. Generators and Demand Side Resources may enter into alternate sales arrangements utilizing any Capacity that has not been scheduled to provide Operating Reserve.

15.4.2 General Day-Ahead Market Rules

15.4.2.1 Bidding and Bid Selection

Resources capable of providing Spinning Reserve, 10-Minute Non-Synchronized Reserve and/or 30-Minute Reserve in the Day-Ahead commitment may submit Availability Bids for each hour of the upcoming day. If a Supplier offers Resources that are capable, based on their indicated commitment status, of providing Operating Reserves but does not submit an Availability Bid, its Day-Ahead Bid will be rejected in its entirety. A Supplier may resubmit a complete Day-Ahead Bid, provided that the new bid is timely.

The ISO may schedule Suppliers that make themselves available to provide Operating Reserves up to the following maximum Operating Reserve levels: (i) for Spinning Reserves, the least of the Resource's emergency response rate multiplied by ten, or the Resource's applicable Upper Operating Limit (*i.e.,* UOL_N, UOL_E); (ii) for 10-Minute Non-Synchronized Reserves, or for non-synchronized 30-Minute Reserves, the Resource's UOL_N or UOL_E, whichever is applicable at the relevant time (the Resource may offer one product or the other depending on the time required for it to start-up and synchronize to the grid; and (iii) for synchronized 30-Minute Reserves, the least of the Resource's emergency response rate multiplied by twenty and its applicable Upper Operating Limit.

However, the sum of the amount of Energy or Demand Reduction a Resource is scheduled to provide, the amount of Regulation Service it is scheduled to provide, and the amount of each Operating Reserves product it is scheduled to provide shall not exceed its UOL_N or UOL_E, whichever is applicable.

For an Energy Storage Resource that is withdrawing Energy, the sum of the Resource's Energy Schedule, the amount of Regulation Capacity it is scheduled to provide, and the amount of Operating Reserves product it is scheduled to provide shall not exceed its Upper Operating Limit.

For Co-located Storage Resources the sum of the amount of Energy each Generator is scheduled to provide, the amount of Regulation Service the Energy Storage Resource is scheduled to provide, and the amount of each Operating Reserves product the Energy Storage Resource is scheduled to provide, shall not exceed the CSR injection Scheduling Limit. The net amount of Energy that the CSR Generators are scheduled to withdraw, plus the amount of Regulation Service the Energy Storage Resource is scheduled to provide, shall not exceed the CSR withdrawal Scheduling Limit.

The ISO shall select Operating Reserve Suppliers for each hour of the upcoming day through a co-optimized Day-Ahead commitment process that minimizes the total bid cost of Energy, Operating Reserves and Regulation Service, using Bids submitted pursuant to Section 4.2 of, and Attachment D to, this ISO Services Tariff. As part of the co-optimization process, the ISO shall determine how much of each Operating Reserves product particular Suppliers will be required to provide in light of the Reliability Rules and other applicable reliability standards, including the locational Operating Reserves requirements specified above.

15.4.2.2 ISO Notice Requirement

The ISO shall notify each Operating Reserve Supplier that has been selected in the Day-Ahead Market of the amount of each Operating Reserve product that it has been scheduled to provide.

15.4.2.3 Real-Time Market Responsibilities of Suppliers Scheduled to Provide Operating Reserves in the Day-Ahead Market

Suppliers that are scheduled Day-Ahead to provide Operating Reserves shall either provide Operating Reserve, Energy or Demand Reductions in real-time when scheduled by the

ISO in all hours for which they have been selected to provide Operating Reserve and are physically capable of doing so. However, Suppliers that are scheduled Day-Ahead to provide Operating Reserves and have startup periods of two hours or less may advise the ISO no later than three hours prior to the first hour of their Day-Ahead schedule that they will not be available to provide Operating Reserves or Energy in real-time under normal conditions. Such Suppliers will be required to settle their Day-Ahead schedule at real-time prices pursuant to Section 15.4.6.3 of this Rate Schedule. The only restriction on Suppliers' ability to exercise this option is that all Suppliers with Day-Ahead Operating Reserves schedules must make the scheduled amount of Capacity available to the ISO for dispatch in the RTD if the ISO initiates a Supplemental Resource Evaluation.

15.4.3 General Real-Time Market Rules

15.4.3.1 Bid Selection

The ISO will automatically select Operating Reserves Suppliers in real-time from eligible Resources, that submit Real-Time Bids pursuant to Section 4.4 of, and Attachment D to, this ISO Services Tariff. Each Supplier will automatically be assigned a real-time Operating Reserves Availability bid of $0/MW for the quantity of Capacity that it makes available to the ISO in its Real-Time Bid. The ISO may schedule Suppliers that make themselves available to provide Operating Reserves up to the following maximum Operating Reserve levels: (i) for Spinning Reserves, the least of the Resource's emergency response rate multiplied by ten and the Resource's applicable Upper Operating Limit (UOL_N or UOL_E); (ii) for 10-Minute Non-Synchronized Reserves, or for non-synchronized 30-Minute Reserves, the Resource's UOL_N or UOL_E, whichever is applicable at the relevant time (the Resource may offer one product or the other depending on the time required for it to start-up and synchronize to the grid); and (iii) for synchronized 30-Minute Reserves, the least of the Resource’s emergency response rate multiplied by twenty and the Resource’s applicable Upper Operating Limit (UOL_N or UOL_E). However, the sum of the amount of Energy or Demand Reduction, that each Resource is scheduled to provide, the amount of Regulation Service it is scheduled to provide, and the amount of each Operating Reserves product it is scheduled to provide shall not exceed its UOL_N or UOL_E, whichever is applicable.

For an Energy Storage Resource that is withdrawing Energy, the sum of the Resource’s Energy Schedule, the amount of Regulation Capacity it is scheduled to provide and the amount of Operating Reserves product it is scheduled to provide shall not exceed its UOL. The ISO may limit the availability of a Withdrawal-Eligible Generator to provide Operating Reserves based on its Energy Level constraints.

For a Co-located Storage Resource the sum of the amount of Energy each Generator is scheduled to provide, the amount of Regulation Service the Energy Storage Resource is scheduled to provide, and the amount of each Operating Reserves product the Energy Storage Resource is scheduled to provide, shall not exceed the CSR injection Scheduling Limit. The net amount of Energy that the CSR Generators are scheduled to withdraw, plus the amount of Regulation Service the Energy Storage Resource is scheduled to provide, shall not exceed the CSR withdrawal Scheduling Limit.

Suppliers will thus be selected on the basis of their response rates, their applicable upper operating limits, and their Energy Bids (which will reflect their opportunity costs) through a co-optimized real-time commitment process that minimizes the total bid cost of Energy, or Demand Reduction, Regulation Service, and Operating Reserves. As part of the process, the ISO shall determine how much of each Operating Reserves product particular Suppliers will be required to provide in light of the Reliability Rules and other applicable reliability standards, including the locational Operating Reserves requirements and Scarcity Reserve Requirements specified above.

15.4.3.2 ISO Notice Requirement

The ISO shall notify each Supplier of Operating Reserve that has been scheduled by RTD of the amount of Operating Reserve that it must provide.

15.4.3.3 Obligation to Make Resources Available to Provide Operating Reserves

Any Resource that is eligible to supply Operating Reserves and that is made available to ISO for dispatch in Real-Time must also make itself available to provide Operating Reserves.

15.4.3.4 Activation of Operating Reserves

All Resources that are selected by the ISO to provide Operating Reserves shall respond to the ISO's directions to activate in real-time.

15.4.3.5 Performance Tracking and Supplier Disqualifications

When a Supplier committed to supply Operating Reserves is activated, the ISO shall measure and track its actual Energy injections and withdrawals, or its Demand Reduction against its expected performance in real-time. The ISO may disqualify Suppliers that consistently fail to provide Energy or Demand Reduction, or to reduce Energy withdrawals, when called upon to do so in real-time from providing Operating Reserves in the future. If a Resource has been disqualified, the ISO shall require it to pass a re-qualification test before accepting any additional Bids to supply Operating Reserves from it. Disqualification and re-qualification criteria shall be set forth in the ISO Procedures.

15.4.4 Operating Reserves Settlements - General Rules

15.4.4.1 Establishing Locational Reserve and Scarcity Reserve Requirement Prices

Except as noted below, the ISO shall calculate separate Day-Ahead Market and Real-Time Market prices for each of the products in five locations: (i) West of Central-East ("West" or "Western"); (ii) East of Central-East excluding Southeastern New York ("Eastern"); (iii) Southeastern New York excluding New York City and Long Island ("Southeastern"); (iv) New York City ("N.Y.C."); and (v) Long Island ("L.I."). The ISO will thus calculate fifteen different locational Operating Reserve prices in both the Day-Ahead Market and the Real-Time Market. The ISO will also calculate prices in the Real-Time Market for each of the products in a Scarcity Reserve Region, if applicable. Day-Ahead locational reserve prices shall be calculated pursuant to Section 15.4.5 of this Rate Schedule. Real-Time locational Operating Reserves prices and Scarcity Reserve Requirement prices shall be calculated pursuant to Section 15.4.6 of this Rate Schedule.

15.4.4.2 Settlements Involving Suppliers of Operating Reserves Located on Long Island

Suppliers of Operating Reserves located on Long Island shall receive settlement payments as if they were providing Operating Reserves located in Southeastern New York, except in the case of a Scarcity Reserve Requirement for a Scarcity Reserve Region that includes Long Island in addition to one or more other Load Zones. In this instance, suppliers of Operating Reserves located on Long Island shall receive settlement payments as if they were providing Operating Reserves located in Southeastern New York and in the applicable Scarcity Reserve Region. The ISO will calculate separate locational Long Island Operating Reserves prices and Long Island Scarcity Reserve Requirement prices for Scarcity Reserve Regions that include Long Island but will not post them or use them for settlement purposes.

15.4.4.3 "Cascading" of Operating Reserves

The ISO will deem Spinning Reserve to be the "highest quality" Operating Reserve, followed by 10-Minute Non-Synchronized Reserve and by 30-Minute Reserve. The ISO shall substitute higher quality Operating Reserves in place of lower quality Operating Reserves, when doing so lowers the total as-bid cost, *i.e.*, when the marginal cost for the higher quality Operating Reserve product is lower than the marginal cost for the lower quality Operating Reserve product, and the substitution of a higher quality for the lower quality product does not cause locational Operating Reserve requirements or Scarcity Reserve Requirements to be violated. To the extent, however, that reliability standards require the use of higher quality Operating Reserves, substitution cannot be made in the opposite direction.

The market clearing price of higher quality Operating Reserves will not be set at a price below the market clearing price of lower quality Operating Reserves in the same location or Scarcity Reserve Region. Thus, the market clearing price of Spinning Reserves will not be below the price for 10-Minute Non-Synchronized Reserves or 30-Minute Reserves and the market clearing price for 10-Minute Non-Synchronized Reserves will not be below the market clearing price for 30-Minute Reserves.

15.4.5 Operating Reserve Settlements – Day-Ahead Market

15.4.5.1 Calculation of Day-Ahead Market Clearing Prices

The ISO shall calculate hourly Day-Ahead Market clearing prices for each Operating Reserve product at each location. Each Day-Ahead Market clearing price shall equal the sum of the relevant Day-Ahead locational Shadow Prices for that product in that hour, subject to the restriction described in Section 15.4.4.3 of this Rate Schedule.

The Day-Ahead Market clearing price for a particular Operating Reserve product in a particular location shall reflect the Shadow Prices associated with all of the ISO-defined Operating Reserve requirements, including locational requirements, that a particular Operating Reserves product from a particular location may be used to satisfy in a given hour. The ISO shall calculate Day-Ahead Market clearing prices using the following formulae:

Market clearing price for Western 30-Minute Reserves = SP1

Market clearing price for Western 10-Minute Non-Synchronized Reserves = SP1 + SP2

Market clearing price for Western Spinning Reserves = SP1 + SP2 + SP3

Market clearing price for Eastern 30-Minute Reserves = SP1 + SP4

Market clearing price for Eastern 10-Minute Non-Synchronized Reserves = SP1 + SP2 + SP4 + SP5

Market clearing price for Eastern Spinning Reserves = SP1 + SP2 + SP3 + SP4 + SP5 + SP6

Market clearing price for Southeastern 30-Minute Reserves = SP1 + SP4 + SP7

Market clearing price for Southeastern 10-Minute Non-Synchronized Reserves = SP1 + SP2 + SP4 + SP5 + SP7 + SP8

Market clearing price for Southeastern Spinning Reserves = SP1 + SP2 + SP3 + SP4 + SP5 + SP6 + SP7 + SP8 + SP9

Market clearing price for N.Y.C. 30-Minute Reserves = SP1 + SP4 + SP7 + SP10

Market clearing price for N.Y.C. 10-Minute Non-Synchronized Reserves = SP1 + SP2 + SP4 + SP5 + SP7 + SP8 + SP10 + SP11

Market clearing price for N.Y.C. Spinning Reserves = SP1 + SP2 + SP3 + SP4 + SP5 + SP6 + SP7 + SP8 + SP9 + SP10 + SP11 + SP12

Market clearing price for L.I. 30-Minute Reserves = SP1 + SP4 + SP7 + SP13

Market clearing price for L.I. 10-Minute Non-Synchronized Reserves = SP1 + SP2 + SP4 + SP5 + SP7 + SP8 + SP13 + SP14

Market clearing price for L.I. Spinning Reserves = SP1 + SP2 + SP3 + SP4 + SP5 + SP6 + SP7 + SP8 + SP9 + SP13 + SP14 + SP15

Where:

SP1 = Shadow Price for total 30-Minute Reserve requirement constraint for the hour

SP2 = Shadow Price for total 10-Minute Reserve requirement constraint for the hour

SP3 = Shadow Price for total Spinning Reserve requirement constraint for the hour

SP4 = Shadow Price for Eastern, Southeastern, N.Y.C., or L.I. 30-Minute Reserve requirement constraint for the hour

SP5 = Shadow Price for Eastern, Southeastern, N.Y.C., or L.I. 10-Minute Reserve requirement constraint for the hour

SP6 = Shadow Price for Eastern, Southeastern, N.Y.C., or L.I. Spinning Reserve requirement constraint for the hour

SP7 = Shadow Price for Southeastern, N.Y.C., or L.I. 30-Minute Reserve requirement constraint for the hour

SP8 = Shadow Price for Southeastern, N.Y.C., or L.I. 10-Minute Reserve requirement constraint for the hour

SP9 =Shadow Price for Southeastern, N.Y.C., or L.I. Spinning Reserve requirement constraint for the hour

SP10 = Shadow Price for New York City 30-Minute Reserve requirement constraint for the hour

SP11 = Shadow Price for New York City 10-Minute Reserve requirement constraint for the hour

SP12 =Shadow Price for New York City Spinning Reserve requirement constraint for the hour

SP13 = Shadow Price for Long Island 30-Minute Reserve requirement constraint for the hour

SP14 = Shadow Price for Long Island 10-Minute Reserve requirement constraint for the hour

SP15 = Shadow Price for Long Island Spinning Reserve requirement constraint for the hour

Day-Ahead locational Shadow Prices will be calculated by SCUC. Each hourly Day-Ahead Shadow Price for each Operating Reserves requirement shall equal the marginal Bid cost of scheduling Resources to provide additional Operating Reserves to meet that requirement in that hour, including any impact on the Bid Production Cost of procuring Energy or Regulation Service that would result from procuring an increment of Operating Reserve to meet the requirement in that hour, as calculated during the fifth SCUC pass described in Section 17.1.3 of Attachment B to this Services Tariff. As a result, the Shadow Price for each Operating Reserves requirement shall include the Day-Ahead Availability Bid of the marginal Resource selected to meet that requirement (or the applicable price on the Operating Reserve Demand Curve for that requirement during shortage conditions), plus any margins on the sale of Energy or Regulation Service in the Day-Ahead Market that that Resource would forego if scheduling it to provide additional Operating Reserve to meet that requirement would lead to it being scheduled to provide less Energy or Regulation Service. Shadow Prices will also be consistent with the Operating Reserve Demand Curves described in Section 15.4.7 of this Rate Schedule, which will ensure that Operating Reserves are not scheduled by SCUC at a cost greater than the relevant Operating Reserve Demand Curve indicates should be paid. If more Operating Reserve of a particular quality than is needed is scheduled to meet a particular locational Operating Reserve requirement, the Shadow Price for that Operating Reserve requirement constraint shall be set at zero.

Each Supplier that is scheduled Day-Ahead to provide Operating Reserve shall be paid the applicable Day-Ahead Market clearing price, based on its location and the quality of

Operating Reserve scheduled, multiplied by the amount of Operating Reserve that the Supplier is scheduled to provide in each hour.

15.4.5.2 Other Day-Ahead Payments

A Supplier that bids on behalf of (i) a Generator that provides Operating Reserves or (ii) a Demand Side Resource that provides Operating Reserves may be eligible for a Day-Ahead Bid Production Cost guarantee payment pursuant to Section 4.6.6 and Attachment C of this ISO Services Tariff.

15.4.6 Operating Reserve Settlements – Real-Time Market

15.4.6.1 Calculation of Real-Time Market Clearing Prices

The ISO shall calculate Real-Time Market clearing prices for each Operating Reserve product for each location in every interval and Scarcity Reserve Region in each interval for which a Scarcity Reserve Requirement is established by the ISO. Each real-time market-clearing price shall equal the sum of the relevant real-time locational Shadow Prices and Scarcity Reserve Requirement Shadow Prices for a given product, subject to the restriction described in Section 15.4.4.3 of this Rate Schedule.

The Real-Time Market clearing price for a particular Operating Reserve product for a particular location or Scarcity Reserve Region shall reflect the Shadow Prices associated with all of the ISO-defined Operating Reserve requirements, including locational requirements and Scarcity Reserve Requirements, that a particular Operating Reserves product from that location or Scarcity Reserve Region may be used to satisfy in a given interval. The ISO shall calculate the Real-Time Market clearing prices using the following formulae:

Market clearing price for Western 30-Minute Reserves = SP1

Market clearing price for Western 10-Minute Non-Synchronized Reserves = SP1 + SP2

Market clearing price for Western Spinning Reserves = SP1 + SP2 + SP3

Market clearing price for Eastern 30-Minute Reserves = SP1 + SP4

Market clearing price for Eastern 10-Minute Non-Synchronized Reserves = SP1 + SP2 + SP4 + SP5

Market clearing price for Eastern Spinning Reserves = SP1 + SP2 + SP3 + SP4 + SP5 + SP6

Market clearing price for Southeastern 30-Minute Reserves = SP1 + SP4 + SP7

Market clearing price for Southeastern 10-Minute Non-Synchronized Reserves = SP1 + SP2 + SP4 + SP5 + SP7 + SP8

Market clearing price for Southeastern Spinning Reserves = SP1 + SP2 + SP3 + SP4 + SP5 + SP6 + SP7 + SP8 + SP9

Market clearing price for N.Y.C. 30-Minute Reserves = SP1 + SP4 + SP7 + SP10

Market clearing price for N.Y.C. 10-Minute Non-Synchronized Reserves = SP1 + SP2 + SP4 + SP5 + SP7 + SP8 + SP10 + SP11

Market clearing price for N.Y.C. Spinning Reserves = SP1 + SP2 + SP3 + SP4 + SP5 + SP6 + SP7 + SP8 + SP9 + SP10 + SP11 + SP12

Market clearing price for L.I. 30-Minute Reserves = SP1 + SP4 + SP7 + SP13

Market clearing price for L.I. 10-Minute Non-Synchronized Reserves = SP1 + SP2 + SP4 + SP5 + SP7 + SP8 + SP13 + SP14

Market clearing price for L.I. Spinning Reserves = SP1 + SP2 + SP3 + SP4 + SP5 + SP6 + SP7 + SP8 + SP9 + SP13 + SP14 +SP15

Where:

SP1 = Shadow Price for total 30-Minute Reserve requirement constraint and, if applicable, Scarcity Reserve Requirement constraint for the interval

SP2 = Shadow Price for total 10-Minute Reserve requirement constraint for the interval

SP3 = Shadow Price for total Spinning Reserve requirement constraint for the interval

SP4 = Shadow Price for Eastern, Southeastern, N.Y.C., or L.I. 30-Minute Reserve requirement constraint and, if applicable, Scarcity Reserve Requirement constraint for the interval

SP5 = Shadow Price for Eastern, Southeastern, N.Y.C., or L.I. 10-Minute Reserve requirement constraint for the interval

SP6 = Shadow Price for Eastern, Southeastern, N.Y.C., or L.I. Spinning Reserve requirement constraint for the interval

SP7 = Shadow Price for Southeastern, N.Y.C., or L.I. 30-Minute Reserve requirement constraint and, if applicable, Scarcity Reserve Requirement constraint for the interval

SP8 = Shadow Price for Southeastern, N.Y.C., or L.I. 10-Minute Reserve requirement constraint for the interval

SP9 = Shadow Price for Southeastern, N.Y.C., or L.I. Spinning Reserve requirement constraint for the interval

SP10 = Shadow Price for New York City 30-Minute Reserve requirement constraint and, if applicable, Scarcity Reserve Requirement constraint for the interval

SP11 = Shadow Price for New York City 10-Minute Reserve requirement constraint for the interval

SP12 =Shadow Price for New York City Spinning Reserve requirement constraint for the interval

SP13 = Shadow Price for Long Island 30-Minute Reserve requirement constraint and, if applicable, Scarcity Reserve Requirement constraint for the interval

SP14 = Shadow Price for Long Island 10-Minute Reserve requirement constraint for the interval

SP15 = Shadow Price for Long Island Spinning Reserve requirement constraint for the interval

Real-time locational and Scarcity Reserve Requirement Shadow Prices will be calculated by the ISO's RTD. Each Real-Time Shadow Price for each Operating Reserves requirement, including a Scarcity Reserve Requirement, in each RTD interval shall equal the marginal Bid cost of scheduling Resources to provide additional Operating Reserves to meet that requirement in that interval, including any impact on the Bid Production Cost of procuring Energy or Regulation Service that would result from procuring an increment of Operating Reserve to meet the requirement in that interval, as calculated during the second RTD pass described in Section 17.1.2.1.2.2 of Attachment B to this ISO Services Tariff. As a result, the Shadow Price for each

Operating Reserves requirement, including a Scarcity Reserve Requirement, shall include the Real-Time Availability Bid of the marginal Resource selected to meet that requirement (or the applicable price on the Operating Reserve Demand Curve or Scarcity Reserve Demand Curve for that requirement during shortage conditions), plus any margins on the sale of Energy or Regulation Service in the Real-Time Market that that Resource would forego if scheduling it to provide additional Operating Reserve to meet that requirement would lead to it being scheduled to provide less Energy or Regulation Service. Shadow Prices will also be consistent with the Operating Reserve Demand Curves and Scarcity Reserve Demand Curve described in Section 15.4.7 of this Rate Schedule, which will ensure that Operating Reserves are not scheduled by RTC at a cost greater than the relevant Operating Reserve Demand Curve or Scarcity Reserve Demand Curve indicates should be paid. If there is more Operating Reserve of the required quality than is needed to meet a particular locational Operating Reserve requirement or Scarcity Reserve Requirement then the Shadow Price for that Operating Reserve requirement or Scarcity Reserve Requirement constraint shall be zero.

Each Supplier that is scheduled in real-time to provide Operating Reserve shall be paid the applicable Real-Time Market clearing price, based on its location and the quality of Operating Reserve scheduled, multiplied by the amount of Operating Reserve that the Supplier is scheduled to provide in each interval that was not scheduled Day-Ahead.

15.4.6.1.1 The Real-Time Market clearing price shall also reflect the Shadow Price for any Scarcity Reserve Requirement constraint as part of the applicable 30-Minute Reserve requirement constraint Shadow Price for the Load Zones included in the Scarcity Reserve Region. The inclusion of Scarcity Reserve Requirement constraint Shadow Prices in the calculation of Real-Time Market clearing prices is as set forth below:

(a) When the Load Zones included in a Scarcity Reserve Region are identical to the Load Zones of an existing locational reserve region, the Scarcity Reserve Requirement will be added to the existing 30-Minute Reserve requirement for the locational reserve region and the Shadow Price for the Scarcity Reserve Requirement will be the Shadow Price for the revised 30-Minute Reserve requirement. The use of Scarcity Reserve Requirement Shadow Prices in calculating Real-Time Market clearing in such circumstances is as follows:

i. If the Scarcity Reserve Requirement is for a Scarcity Reserve Region that includes Load Zones A, B, C, D, E, F, G, H, I, J, and K (*i.e.*, all Load Zones), then the Shadow Price for the Scarcity Reserve Requirement shall be SP1. SP1 shall be utilized in the same manner as described in the formulae above in calculating Real-Time Market clearing prices;

ii. If the Scarcity Reserve Requirement is for a Scarcity Reserve Region that includes Load Zones F, G, H, I, J, and K (*i.e.*, all East of Central-East Load Zones), but does not include Load Zones A, B, C, D, or E, then the Shadow Price for the Scarcity Reserve Requirement shall be SP4. SP4 shall be utilized in the same manner as described in the formulae above in calculating Real-Time Market clearing prices;

iii. If the Scarcity Reserve Requirement is for a Scarcity Reserve Region that includes Load Zones G, H, I, J, and K (*i.e.*, all Southeastern New York Load Zones), but does not include Load Zones A, B, C, D, E, or F, then the Shadow

Price for the Scarcity Reserve Requirement shall be SP7. SP7 shall be utilized in the same manner as described in the formulae above in calculating Real-Time Market clearing prices;

iv. If the Scarcity Reserve Requirement is for a Scarcity Reserve Region that includes Load Zone J (*i.e.*, New York City only), but does not include Load Zones A, B, C, D, E, F, G, H, I, or K, then the Shadow Price for the Scarcity Reserve Requirement shall be SP10. SP10 shall be utilized in the same manner as described in the formulae above in calculating Real-Time Market clearing prices; or

v. If the Scarcity Reserve Requirement is for a Scarcity Reserve Region that includes Load Zone K (*i.e.*, Long Island only), but does not include Load Zones A, B, C, D, E, F, G, H, I, or J, then the Shadow Price for the Scarcity Reserve Requirement shall be SP13. SP13 shall be utilized in the same manner as described in the formulae above in calculating Real-Time Market clearing prices.

(b) When the Load Zones included in the Scarcity Reserve Region are not identical to the Load Zones of an existing locational reserve region, the Shadow Price attributable to the Scarcity Reserve Requirement will be added to the applicable Shadow Price for the 30-Minute Reserve requirement for the existing locational reserve region to which all of the Load Zones included in the Scarcity Reserve Region belong. The inclusion of the Scarcity Reserve Requirement Shadow Prices shall apply only to the Load Zones included as part of a Scarcity Reserve Region. The use of Scarcity Reserve Requirement Shadow Prices in calculating Real-Time Market clearing in such circumstances is as follows:

i. If the Scarcity Reserve Requirement is for a Scarcity Reserve Region that includes at least one or more of Load Zones A, B, C, D, or E and Section 15.4.6.1.1(a)(i) of this Rate Schedule is not applicable, then the Shadow Price for the Scarcity Reserve Requirement shall be included in SP1 for each of the Load Zones included in the Scarcity Reserve Region. This SP1 value shall be utilized in the same manner as described in the formulae above in calculating Real-Time Market clearing prices for each of the Load Zones included in the Scarcity Reserve Region;

ii. If the Scarcity Reserve Requirement is for a Scarcity Reserve Region that includes at least Load Zone F, but does not include Load Zones A, B, C, D, or E and Section 15.4.6.1.1(a)(ii) of this Rate Schedule is not applicable, then the Shadow Price for the Scarcity Reserve Requirement shall be included in SP4 for each of the Load Zones included in the Scarcity Reserve Region. This SP4 value shall be utilized in the same manner as described in the formulae above in calculating Real-Time Market clearing prices for each of the Load Zones included in the Scarcity Reserve Region; or

iii. If the Scarcity Reserve Requirement is for a Scarcity Reserve Region that includes at least one or more of Load Zones G, H, I, J, or K but does not include Load Zones A, B, C, D, E, or F and Sections 15.4.6.1.1(a)(iii), 15.4.6.1.1(a)(iv), or 15.4.6.1.1(a)(v) of this Rate Schedule are not applicable, then the Shadow Price for the Scarcity Reserve Requirement shall be included in SP7 for each of the Load Zones included in the Scarcity Reserve Region. This SP7 value shall be utilized in the same manner as described in the formulae above in calculating

Real-Time Market clearing prices for each of the Load Zones included in the Scarcity Reserve Region.

15.4.6.2 Establishment of Scarcity Reserve Requirements in the Real-Time Market During EDRP/SCR Activations

The ISO will establish a Scarcity Reserve Requirement for each Scarcity Reserve Region when it has called upon the EDRP and/or SCRs in identified Load Zones to reduce Load to address a reliability need. The Scarcity Reserve Requirement will be applicable for all real-time intervals during which the ISO has activated EDRP and/or SCRs within the applicable Scarcity Reserve Region to provide Load reduction. The Scarcity Reserve Requirement for each affected real-time interval shall be an amount equal to the sum of the applicable values for the Expected EDRP/SCR MW for all of the Load Zones included in a Scarcity Reserve Region, less the Available Operating Capacity in the Scarcity Reserve Region; provided, however, that a Scarcity Reserve Requirement shall not have a value less than zero.

The applicable value of the Expected EDRP/SCR MW for each Load Zone included in a Scarcity Reserve Region to be used in calculating the Scarcity Reserve Requirement is dependent upon whether the Load reduction for a given interval is deemed voluntary or mandatory for purposes of calculating the Scarcity Reserve Requirement, as further described below. If the ISO has satisfied the notification requirements set forth in Section 5.12.11.1 of this ISO Services Tariff for the SCRs within any Load Zone for any hour encompassed by the EDRP/SCR activation(s) for the day at issue, the Load reduction for all intervals encompassed by such activation(s) are deemed to be mandatory for the purposes of calculating any Scarcity Reserve Requirement only and the corresponding value for a mandatory Load reduction is used for SCRs in determining any Scarcity Reserve Requirement. In all other circumstances not encompassed by the preceding sentence, the Load reduction for all intervals encompassed by such EDRP/SCR activation(s) are deemed to be voluntary for the day at issue and the corresponding value for a voluntary Load reduction is used for SCRs in determining any Scarcity Reserve Requirement. For EDRP, Load reduction is deemed to be voluntary in all intervals and the value for EDRP included in the Expected EDRP/SCR MW value for each Load Zone reflects the voluntary nature of the Load reduction.

15.4.6.3 Operating Reserve Balancing Payments

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 ISO, shall be settled pursuant to the following rules.

(a) When the Supplier's real-time Operating Reserves schedule is less than its Day-Ahead Operating Reserves schedule, the Supplier shall pay 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 or Scarcity Reserve Region; and (ii) the difference between the Supplier's Day-Ahead and real-time Operating Reserves schedules.

(b) When the Supplier's real-time Operating Reserves schedule is greater than its Day-Ahead Operating Reserves schedule, the ISO shall pay the Supplier an amount to compensate it 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 or Scarcity Reserve Region; and (ii) the difference between the Supplier's Day-Ahead and real-time Operating Reserves schedules.

15.4.6.4 Other Real-Time Payments

The ISO shall pay Generators that are selected to provide Operating Reserves Day-Ahead, but are directed to convert to Energy production or, for Withdrawal-Eligible Generators, to reduce Energy withdrawals in real-time, the applicable Real-Time LBMP for all Energy they are directed to provide in excess of their Day-Ahead Energy schedule.

A Supplier that bids on behalf of (i) a Generator that provides Operating Reserves or (ii) a Demand Side Resource that provides Operating Reserves may be eligible for a Bid Production Cost guarantee payment pursuant to Section 4.6.6 and Attachment C of this ISO Services Tariff.

A Supplier that provides Operating Reserves may also be eligible for a Day-Ahead Margin Assurance Payment pursuant to Section 4.6.5 and Attachment J of this ISO Services Tariff.

15.4.7 Operating Reserve Demand Curves and Scarcity Reserve Demand Curve

The ISO shall establish Operating Reserve Demand Curves for each locational Operating Reserves requirement. Specifically, there shall be a demand curve for: (i) Total Spinning Reserves; (ii) Eastern, Southeastern, New York City, or Long Island Spinning Reserves; (iii) Southeastern, New York City, or Long Island Spinning Reserves; (iv) New York City Spinning Reserves; (v) Long Island Spinning Reserves; (vi) Total 10-Minute Reserves; (vii) Eastern, Southeastern, New York City, or Long Island 10-Minute Reserves; (viii) Southeastern, New York City, or Long Island 10-Minute Reserves; (ix) New York City 10-Minute Reserves; (x) Long Island 10-Minute Reserves; (xi) Total 30-Minute Reserves (including separate demand curves applicable for each real-time interval the ISO has established a Scarcity Reserve Requirement); (xii) Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves (including separate demand curves applicable for each real-time interval the ISO has established certain Scarcity Reserve Requirements); (xiii) Southeastern, New York City, or Long Island 30-Minute Reserves (including separate demand curves applicable for each real-time interval the ISO has established certain Scarcity Reserve Requirements); (xiv) New York City 30-Minute Reserves (including a separate demand curve applicable for each real-time interval the ISO has established a Scarcity Reserve Requirement for which the pricing rules established in Section 15.4.6.1.1(a)(iv) of this Rate Schedule apply); and (xv) Long Island 30-Minute Reserves (including a separate demand curve applicable for each real-time interval the ISO has established a Scarcity Reserve Requirement for which the pricing rules established in Section 15.4.6.1.1(a)(v) of this Rate Schedule apply). Each Operating Reserve Demand Curve will apply to both the Day-Ahead Market and the Real-Time Market for the relevant product and location, except for those demand curves that apply to certain Scarcity Reserve Requirements which will be applicable only during the real-time intervals that a Scarcity Reserve Requirement has been established by the ISO. The ISO shall also establish a Scarcity Reserve Demand Curve for each Scarcity Reserve Requirement established by the ISO in the Real-Time Market for which the pricing rules established in Section 15.4.6.1.1(b) of this Rate Schedule apply. A Scarcity Reserve Demand Curve will be applicable only during the real-time intervals that such a Scarcity Reserve Requirement has been established by the ISO.

The market clearing pricing for Operating Reserves shall be calculated pursuant to Sections 15.4.5.1 and 15.4.6.1 of this Rate Schedule and in a manner consistent with the demand curves established in this Section so that Operating Reserves are not purchased by SCUC, RTC or RTD at a cost higher than the relevant demand curve indicates should be paid.

The ISO Procedures shall establish and post a target level for each locational Operating Reserves requirement for each hour, which will be the number of MW of Operating Reserves meeting that requirement that the ISO would seek to maintain in that hour. To the extent not otherwise already adjusted pursuant to Section 15.4.6.1.1(a) of this Rate Schedule, during each real-time interval in which the ISO has established a Scarcity Reserve Requirement, the ISO will adjust the target level for the locational 30-Minute Reserves requirement to account for the Scarcity Reserve Requirement within the existing locational reserve region(s) to which all the Load Zones included in the Scarcity Reserve Region belong. The ISO will then define an Operating Reserves demand curve for that hour corresponding to each Operating Reserves requirement as follows:

(a) Total Spinning Reserves: For quantities of Operating Reserves meeting the total Spinning Reserves requirement that are less than or equal to the target level for that locational requirement, the price on the total Spinning Reserves demand curve shall be $775/MW. For all other quantities, the price on the total Spinning Reserves demand curve shall be $0/MW.

(b) Eastern, Southeastern, New York City, or Long Island Spinning Reserves: For quantities of Operating Reserves meeting the Eastern, Southeastern, New York City, or Long Island Spinning Reserves requirement that are less than or equal to the target level for that locational requirement, the price on the Eastern, Southeastern, New York City, or Long Island Spinning Reserves demand curve shall be $25/MW. For all other quantities, the price on the Eastern, Southeastern, New York City, or Long Island Spinning Reserves demand curve shall be $0/MW.

(c) Southeastern, New York City, or Long Island Spinning Reserves: For quantities of Operating Reserves meeting the Southeastern, New York City, or Long Island

Spinning Reserves requirement that are less than or equal to the target level for that locational requirement, the price on the Southeastern, New York City, or Long Island Spinning Reserves demand curve shall be $25/MW. For all other quantities, the price on the Southeastern, New York City, or Long Island Spinning Reserves demand curve shall be $0/MW.

(d) New York City Spinning Reserves: For quantities of Operating Reserves meeting the New York City Spinning Reserves requirement that are less than or equal to the target level for that locational requirement, the price on the New York City Spinning Reserves demand curve shall be $25/MW. For all other quantities, the price on the New York City Spinning Reserves demand curve shall be $0/MW.

(e) Long Island Spinning Reserves: For quantities of Operating Reserves meeting the Long Island Spinning Reserves requirement that are less than or equal to the target level for that locational requirement, the price on the Long Island Spinning Reserves demand curve shall be $25/MW. For all other quantities, the price on the Long Island Spinning Reserves demand curve shall be $0/MW.

(f) Total 10-Minute Reserves: For quantities of Operating Reserves meeting the total 10-minute reserves requirement that are less than or equal to the target level for that locational requirement, the price on the total 10-minute reserves demand curve shall be $750/MW. For all other quantities, the price on the total 10-minute reserves demand curve shall be $0/MW.

(g) Eastern, Southeastern, New York City, or Long Island 10-Minute Reserves: For quantities of Operating Reserves meeting the Eastern, Southeastern, New York City, or Long Island 10-minute reserves requirement that are less than or equal to the target level for that locational requirement, the price on the Eastern, Southeastern, New York City, or Long Island 10-minute reserves demand curve shall be $775/MW. For all other quantities, the price on the Eastern, Southeastern, New York City, or Long Island 10-minute reserves demand curve shall be $0/MW.

(h) Southeastern, New York City, or Long Island 10-Minute Reserves: For quantities of Operating Reserves meeting the Southeastern, New York City, or Long Island 10-Minute Reserves requirement that are less than or equal to the target level for that locational requirement, the price on the Southeastern, New York City, or Long Island 10-Minute Reserves demand curve shall be $25/MW. For all other quantities, the price on the Southeastern, New York City, or Long Island 10-Minute Reserves demand curve shall be $0/MW.

(i) New York City 10-Minute Reserves: For quantities of Operating Reserves meeting the New York City 10-minute reserves requirement that are less than or equal to the target level for that locational requirement, the price on the New York City 10-minute reserves demand curve shall be $25/MW. For all other quantities, the price on the New York City 10-minute reserves demand curve shall be $0/MW.

(j) Long Island 10-Minute Reserves: For quantities of Operating Reserves meeting the Long Island 10-minute reserves requirement that are less than or equal to the target level for that locational requirement, the price on the Long Island 10-minute reserves demand curve shall be $25/MW. For all other quantities, the price on the Long Island 10-minute reserves demand curve shall be $0/MW.

(k) Total 30-Minute Reserves: For quantities of Operating Reserves meeting the total 30-Minute Reserves requirement that are less than or equal to the target level for that locational requirement minus 955 MW, the price on the total 30-Minute Reserves demand curve shall be $750/MW. For quantities of Operating Reserves meeting the total 30-Minute Reserves requirement that are less than or equal to the target level for that locational requirement minus 655 MW but that exceed the target level for that locational requirement minus 955 MW, the price on the total 30-Minute Reserves demand curve shall be $200/MW. For quantities of Operating Reserves meeting the total 30-Minute Reserves requirement that are less than or equal to the target level for that locational requirement minus 300 MW but that exceed the target level for that locational requirement minus 655 MW, the price on the total 30-Minute Reserves demand curve shall be $100/MW. For quantities of Operating Reserves meeting the total 30-Minute Reserves requirement that are less than or equal to the target level for that locational requirement but that exceed the target level for that locational requirement minus 300 MW, the price on the total 30-Minute Reserves demand curve shall be $25/MW. For all other quantities, the price on the total 30-Minute Reserves demand curve shall be $0/MW. However, the ISO will not schedule more total 30-Minute Reserves than the level defined by the requirement for that hour. During each real-time interval that the ISO has established a Scarcity Reserve Requirement in the Real-Time Market for which the pricing rules established in Section 15.4.6.1.1(a)(i) of this Rate Schedule apply, the applicable Operating Reserves demand curve for total 30-Minute Reserves shall be as follows: For quantities of Operating Reserves meeting the total 30-Minute Reserves locational requirement target level plus the Scarcity Reserve Requirement ("NYCA scarcity target level") that are less than or equal to the NYCA scarcity target level minus an amount equal to the sum of 955 MW and the Scarcity Reserve Requirement, the price on the total 30-Minute Reserves demand curve shall be $750/MW. For quantities of Operating Reserves meeting the NYCA scarcity target level that are less than or equal to the NYCA scarcity target level but that exceed the NYCA scarcity target level minus an amount equal to the sum of 955 MW and the Scarcity Reserve Requirement, the price on the total 30-Minute Reserves demand curve shall be $500/MW. For all other quantities, the price on the total 30-Minute Reserves demand curve shall be $0/MW. However, the ISO will not schedule more total 30-Minute Reserves than the level defined by the total 30-Minute Reserves locational requirement plus the Scarcity Reserve Requirement for that interval.

During each real-time interval that the ISO has established a Scarcity Reserve Requirement(s) in the Real-Time Market, other than a Scarcity Reserve Requirement for which the pricing rules established in Section 15.4.6.1.1(a)(i) of this Rate Schedule apply, the applicable Operating Reserves demand curve for total 30-Minute Reserves shall be as follows: For quantities of Operating Reserves meeting the total 30-Minute Reserves locational requirement target level plus the applicable Scarcity Reserve Requirement(s) ("adjusted NYCA target level") that are less than or equal to the adjusted NYCA target level minus 955 MW, the price on the total 30-Minute Reserves demand curve shall be $750/MW.

For quantities of Operating Reserves meeting the adjusted NYCA target level that are less than or equal to the adjusted NYCA target level but that exceed the adjusted NYCA target level minus 955 MW, the price on the total 30-Minute Reserves demand curve shall be $500/MW. For all other quantities, the price on the total 30-Minute Reserves demand curve shall be $0/MW. However, the ISO will not schedule more total 30-Minute Reserves than the level defined by the total 30-Minute Reserves locational requirement plus the applicable Scarcity Reserve Requirement(s) for that interval.

(l) Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves: For quantities of Operating Reserves meeting the Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves requirement that are less than or equal to the target level for that locational requirement, the price on the Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be $25/MW. For all other quantities, the price on the Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be $0/MW.

During each real-time interval that the ISO has established a Scarcity Reserve Requirement in the Real-Time Market for which the pricing rules established in Section 15.4.6.1.1(a)(ii) of this Rate Schedule apply, the applicable Operating Reserves demand curve for Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves shall be as follows: For quantities of Operating Reserves meeting the Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves locational requirement target level plus the Scarcity Reserve

Requirement ("Eastern scarcity target level") that are less than or equal to the Eastern scarcity target level minus an amount equal to the Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves locational requirement target, the price on the Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be $500/MW. For the quantities of Operating Reserves meeting the Eastern scarcity target level that are less than or equal to the Eastern scarcity target level but exceed the Eastern scarcity target level minus an amount equal to the Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves locational requirement target level, the price on the Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be $25/MW. For all other quantities, the price on the Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be $0/MW.

During each real-time interval that the ISO has established a Scarcity Reserve Requirement(s) in the Real-Time Market for which all the Load Zones encompassed by such Scarcity Reserve Requirement belong to the East of Central-East reserve region, other than a Scarcity Reserve Requirement for which the pricing rules established in Section 15.4.6.1.1(a)(ii) of this Rate Schedule apply, the applicable Operating Reserves demand curve for Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves shall be as follows: For quantities of Operating Reserves meeting the Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves locational requirement target level plus the applicable Scarcity Reserve Requirement(s) ("adjusted Eastern target level") that are less than or equal to the adjusted Eastern target level, the price on the Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be $25/MW. For all other quantities, the price on the Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be $0/MW.

(m) Southeastern, New York City, or Long Island 30-Minute Reserves: For quantities of Operating Reserves meeting the Southeastern, New York City, or Long Island 30-Minute Reserves requirement that are less than or equal to the target level for that locational requirement minus any incremental 30-Minute Reserve target level established by the ISO for an amount not to exceed 500 MW ("SENY incremental reserve target level"), the price on the Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be $500/MW. For quantities of Operating Reserves meeting the Southeastern, New York City, or Long Island 30-Minute Reserves requirement that are less than or equal to the target level for that locational requirement but that exceed the target level for that locational requirement minus the SENY incremental reserve target level, the price on the Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be $25/MW. For all other quantities, the price on the Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be $0/MW. During each real-time interval that the ISO has established a Scarcity Reserve Requirement in the Real-Time Market for which the pricing rules established in Section 15.4.6.1.1(a)(iii) of this Rate Schedule apply, the applicable Operating Reserves demand curve for Southeastern, New York City, or Long Island 30-

Minute Reserves shall be as follows: For quantities of Operating Reserves meeting the Southeastern, New York City, or Long Island 30-Minute Reserves locational requirement target level plus the Scarcity Reserve Requirement ("Southeastern scarcity target level") that are less than or equal to the Southeastern scarcity target level minus the SENY incremental reserve target level, the price on the Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be $500/MW. For quantities of Operating Reserves meeting the Southeastern scarcity target level that are less than or equal to the Southeastern scarcity target level but that exceed the Southeastern scarcity target level minus the SENY incremental reserve target level, the price on the Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be $25/MW. For all other quantities, the price on the Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be $0/MW. During each real-time interval that the ISO has established a Scarcity Reserve Requirement(s) in the Real-Time Market for which all the Load Zones encompassed by such Scarcity Reserve Requirement belong to the Southeastern New York reserve region, other than a Scarcity Reserve Requirement for which the pricing rules established in Section 15.4.6.1.1(a)(iii) of this Rate Schedule apply, the applicable Operating Reserves demand curve for Southeastern, New York City, or Long Island 30-Minute Reserves shall be as follows: For quantities of Operating Reserves meeting the Southeastern, New York City, or Long Island 30-Minute Reserves locational requirement target level plus the applicable Scarcity Reserve Requirement(s) ("adjusted Southeastern target level") that are less than or equal to the adjusted Southeastern target level minus the SENY incremental reserve target level, the price on the Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be $500/MW. For quantities of Operating Reserves meeting the adjusted Southeastern target level that are less than or equal to the adjusted Southeastern target level but that exceed the adjusted Southeastern target level minus the SENY incremental reserve target level, the price on the Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be $25/MW. For all other quantities, the price on the Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be $0/MW.

(n) New York City 30-Minute Reserves: For quantities of Operating Reserves meeting the New York City 30-Minute Reserves requirement that are less than or equal to the target level for that locational requirement, the price on the New York City 30-Minute Reserves demand curve shall be $25/MW. For all other quantities, the price on the New York City 30-Minute Reserves demand curve shall be $0/MW.

During each real-time interval that the ISO has established a Scarcity Reserve Requirement in the Real-Time Market for which the pricing rules established in Section 15.4.6.1.1(a)(iv) of this Rate Schedule apply, the applicable Operating Reserves demand curve for New York City 30-Minute Reserves shall be as follows: For quantities of Operating Reserves meeting the New York City 30-Minute Reserves locational requirement target level plus the Scarcity Reserve Requirement ("N.Y.C. scarcity target level") that are less than or equal to the

N.Y.C. scarcity target level minus an amount equal to the New York City 30-Minute Reserves locational requirement target, the price on the New York City 30-Minute Reserves demand curve shall be $500/MW. For the quantities of Operating Reserves meeting the N.Y.C. scarcity target level that are less than or equal to the N.Y.C. scarcity target level but exceed the N.Y.C. scarcity target level minus an amount equal to the New York City 30-Minute Reserves locational requirement target level, the price on the New York City 30-Minute Reserves demand curve shall be $25/MW. For all other quantities, the price on the New York City 30-Minute Reserves demand curve shall be $0/MW.

(o) Long Island 30-Minute Reserves: For quantities of Operating Reserves meeting the Long Island 30-Minute Reserves requirement that are less than or equal to the target level for that locational requirement, the price on the Long Island 30-Minute Reserves demand curve shall be $25/MW. For all other quantities, the price on the Long Island 30-Minute Reserves demand curve shall be $0/MW. During each real-time interval that the ISO has established a Scarcity Reserve Requirement in the Real-Time Market for which the pricing rules established in Section 15.4.6.1.1(a)(v) of this Rate Schedule apply, the applicable Operating Reserves demand curve for Long Island 30-Minute Reserves shall be as follows: For quantities of Operating Reserves meeting the Long Island 30-Minute Reserves locational requirement target level plus the Scarcity Reserve Requirement ("Long Island scarcity target level") that are less than or equal to the Long Island scarcity target level minus an amount equal to the Long Island 30-Minute Reserves locational requirement target, the price on the Long Island 30-

Minute Reserves demand curve shall be $500/MW. For the quantities of Operating Reserves meeting the Long Island scarcity target level that are less than or equal to the Long Island scarcity target level but exceed the Long Island scarcity target level minus an amount equal to the Long Island 30-Minute Reserves locational requirement target level, the price on the Long Island 30-Minute Reserves demand curve shall be $25/MW. For all other quantities, the price on the Long Island 30-Minute Reserves demand curve shall be $0/MW.

The ISO will procure additional Operating Reserves to meet each Scarcity Reserve Requirement established by the ISO in the Real-Time Market for which the pricing rules established in Section 15.4.6.1.1(b) of this Rate Schedule apply. The Scarcity Reserve Demand Curve for each real-time interval in which the ISO has established such a Scarcity Reserve Requirement shall be defined as follows: For quantities of Operating Reserves meeting the Scarcity Reserve Requirement that are less than or equal to the Scarcity Reserve Requirement, the price on the Scarcity Reserve Demand Curve shall be $500/MW. For all other quantities, the price on the Scarcity Reserve Demand Curve shall be $0/MW.

In order to respond to operational or reliability problems that arise in real-time, the ISO may procure any Operating Reserve product at a quantity and/or price point different than those specified above. The ISO shall post a notice of any such purchase as soon as reasonably possible and shall report on the reasons for such purchases at the next meeting of its Business Issues Committee. The ISO shall also immediately initiate an investigation to determine whether it is necessary to modify the quantity and price points specified above to avoid future operational or reliability problems. The ISO will consult with its Market Monitoring Unit when it conducts this investigation.

If the ISO determines that it is necessary to modify the quantity and/or price points specified above in order to avoid future operational or reliability problems it may temporarily modify them for a period of up to ninety days. If circumstances reasonably allow, the ISO will consult with its Market Monitoring Unit, the Business Issues Committee, the Commission, and the PSC before implementing any such modification. In all circumstances, the ISO will consult with those entities as soon as reasonably possible after implementing a temporary modification.

Not later than 90 days after the implementation of the Operating Reserves Demand Curves the ISO, in consultation with its Market Advisor, shall conduct an initial review of them in accordance with the ISO Procedures. The scope of the review shall include, but not be limited to, an analysis of whether any Operating Reserve Demand Curve should be adjusted upward or downward in order to optimize the economic efficiency of any, or all, of the ISO Administered Markets. The ISO and the Market Advisor shall perform additional quarterly reviews, subject to the same scope requirement, during the remainder of the first year that this Section 15.4.7 is in effect. After the first year, the ISO shall perform periodic reviews, subject to the same scope requirement, and the Market Monitoring Unit shall be given the opportunity to review and comment on the ISO's periodic reviews of the Operating Reserve Demand Curves and Scarcity Reserve Demand Curve.

The responsibilities of the Market Monitoring Unit that are addressed in the above section of Rate Schedule 4 to the Services Tariff are also addressed in Section 30.4.6.4.2 of Attachment O.

15.4.8 Self-Supply

Transactions may be entered into to provide for Self-Supply of Operating Reserves. Except as noted in the next paragraph, Customers seeking to Self-Supply Operating Reserves must place the Generator(s) supplying any one of the Operating Reserves under ISO control. The Generator(s) must meet ISO rules for acceptability. The amount that any such Customer will be charged for Operating Reserves will be reduced by the market value of the services provided by the specified Generator(s) as determined in the ISO Services Tariff.

Alternatively, Customers, including LSEs, may enter into Day-Ahead Bilateral financial Transactions, *e.g.*, contracts-for-differences, in order to hedge against price volatility in the Operating Reserves markets.

17.1 LBMP Calculation

The Locational Based Marginal Prices ("LBMPs" or "prices") for Suppliers and Loads in the Real-Time Market will be based on the system marginal costs produced by the Real-Time Dispatch ("RTD") program and during intervals when certain conditions exist at Proxy Generator Buses, the Real-Time Commitment ("RTC") program. LBMPs for Suppliers and Loads in the Day-Ahead Market will be based on the system marginal costs produced by the Security Constrained Unit Commitment ("SCUC"). LBMPs calculated by SCUC and RTD will incorporate the incremental dispatch costs of Dispatchable Resources that would be scheduled to meet an increment of Load. For pricing purposes, the incremental dispatch costs of Fast-Start Resources that Bid ISO-Committed Flexible shall be adjusted to include start-up costs and minimum generation costs based on the Start-Up Bids and Minimum Generation Bids or mitigated Start-Up Bids and Minimum Generation Bids of each such Resource, as described in Section 17.1.1.2 below.

To the extent that tradeoffs exist between scheduling providers to produce Energy or reduce demand, and scheduling them to provide Regulation Service or Operating Reserves, LBMPs shall reflect the effect of meeting an increment of Load, given those tradeoffs, at each location on the Bid Production Cost associated with those services. As such, those LBMPs may incorporate: (i) Bids for Regulation Service or Operating Reserves; or (ii) shortage costs associated with the inability to meet a Regulation Service or Operating Reserves requirement under the Regulation Service Demand Curve set forth in Rate Schedule 3 of this ISO Services Tariff and Operating Reserve Demand Curves and Scarcity Reserve Demand Curve set forth in Rate Schedule 4 of this ISO Services Tariff. For the purposes of calculating LBMPs under this

Services Tariff Section 17, Energy withdrawals by Withdrawal-Eligible Generators are treated as negative generation, and can set price.

Additionally, for the purpose of calculating Real-Time LBMPs when RTD is committing and dispatching Resources meeting Minimum Generation Levels and capable of starting in ten minutes pursuant to Section 4.4.2.4 of this ISO Services Tariff, RTD shall include in the incremental dispatch cost of each such Resource a start-up cost based on the Start-Up Bid of each such Resource and shall assume for each such Resource a zero downward response rate.

17.1.1 LBMP Bus Calculation Method

System marginal costs will be utilized in an *ex ante* computation to produce Day-Ahead and Real-Time LBMP bus prices using the following equations.

The LBMP at bus i can be written as:

$$\gamma_i = \lambda^R + \gamma_i^L + \gamma_i^C$$

Where:

γ_i	=	LBMP at bus *i* in \$/MWh
λ^R	=	the system marginal price at the Reference Bus
γ_i^L	=	Marginal Losses Component of the LBMP at bus *i* which is the marginal cost of losses at bus *i* relative to the Reference Bus
γ_i^C	=	Congestion Component of the LBMP at bus *i* which is the marginal cost of Congestion at bus *i* relative to the Reference Bus

The Marginal Losses Component of the LBMP at any bus i is calculated using the equation:

$$\gamma_i^L = (DF_i - 1)\lambda^R$$

Where:

DF_i = delivery factor for bus *i* to the system Reference Bus and:

$$DF_i = \left(1 - \frac{\partial L}{\partial P_i}\right)$$

Where:

L = NYCA losses; and

P_i = injection at bus i

The Congestion Component of the LBMP at bus i is calculated using the equation:

$$\gamma_i^c = -\left(\sum_{k \in K}^{n} GF_{ik}\mu_k\right)$$

Where:

K = the set of Constraints;

GF_{ik} = Shift Factor for bus *i* on Constraint *k* in the pre- or post-Contingency case which limits flows across that Constraint (the Shift Factor measures the incremental change in flow on Constraint *k*, expressed in per unit, for an increment of injection at bus *i* and a corresponding withdrawal at the Reference Bus); and

μ_k = the Shadow Price of Constraint *k* expressed in $/MWh, provided however, this Shadow Price shall not exceed the Transmission Shortage Cost.

Substituting the equations for γ_i^L and γ_i^C into the first equation yields:

$$\gamma_i = \lambda^R + (DF_i - 1)\lambda^R - \sum_{k \epsilon K} GF_{ik}\mu_k$$

LBMPs will be calculated for the Day-Ahead and the Real-Time Markets. In the Day-Ahead Market, the three components of the LBMP at each location will be calculated from the SCUC results and posted for each of the twenty four (24) hours of the next day. The Real-Time LBMPs will be calculated and posted for each execution of RTD.

17.1.1.1 Determining Shift Factors and Incremental System Losses

For the purposes of pricing and scheduling, Shift Factors, GF_{ik}, and loss delivery factors, DF_i, will reflect expected power flows, including expected unscheduled power flows. When determining prices and schedules, SCUC, RTC and RTD shall include both the expected power flows resulting from NYISO interchange schedules (*see* Section 17.1.1.1.2), and expected unscheduled power flows (*see* Section 17.1.1.1.1). All NYCA Resource, NYCA Load and Proxy Generator Bus Shift Factors and loss delivery factors will incorporate internal and coordinated external transmission facility outages, power flows due to schedules, and expected unscheduled power flows.

17.1.1.1.1 Determining Expected Unscheduled Power Flows

In the Day-Ahead Market, expected unscheduled power flows will ordinarily be determined based on historical, rolling 30-day on-peak and off-peak averages. To ensure expected unscheduled power flows accurately reflect anticipated conditions, the frequency and/or period used to determine the historical average may be modified by the NYISO to address market rule, system topology, operational, or other changes that would be expected to significantly impact unscheduled power flows. The NYISO will publicly post the Day-Ahead on-peak and off-peak unscheduled power flows on its web site.

In the Real-Time Market, expected unscheduled power flows will ordinarily be determined based on current power flows, modified to reflect expected changes over the real-time scheduling horizon.

17.1.1.1.2 Determining Expected Power Flows Resulting from NYISO Interchange Schedules

In the Day-Ahead Market, for purposes of scheduling and pricing, SCUC will establish expected power flows for the ABC interface, JK interface and Branchburg-Ramapo interconnection based on the following:

a. Consolidated Edison Company of New York's Day-Ahead Market hourly election under OATT Attachment CC, Schedule C;

b. The percentage of PJM-NYISO scheduled interchange that is expected to flow over the Branchburg-Ramapo interconnection. The expected flow may also be adjusted by a MW offset to reflect expected operational conditions;

c. The percentage of PJM-NYISO scheduled interchange (if any) that is expected to flow over the ABC interface; and

d. The percentage of PJM-NYISO scheduled interchange (if any) that is expected to flow over the JK interface.

The terms "ABC interface" and "JK interface" have the meaning ascribed to them in Schedule C to Attachment CC to the OATT.

The NYISO shall post the percentage values it is currently using to establish Day-Ahead and real-time expected Branchburg-Ramapo interconnection, ABC interface and JK interface flows for purposes of scheduling and pricing on its web site. If the NYISO determines it is necessary to change the posted Branchburg-Ramapo, ABC or JK percentage values, it will provide notice to its Market Participants as far in advance of the change as is practicable under the circumstances.

In the Day-Ahead Market, scheduled interchange that is not expected to flow over the ABC interface, JK interface or Branchburg-Ramapo interconnection (or on Scheduled Lines) will be expected to flow over the NYISO's other interconnections. Expected flows over the NYISO's other interconnections will be determined consistent with the expected impacts of scheduled interchange and consistent with shift factors and delivery factors calculated in accordance with Section 17.1.1.1, above.

For pricing purposes, flows in the Real-Time Market will be established for the ABC interface, JK interface, and Branchburg-Ramapo interconnection based on the current flow, modified to reflect the expected incremental impacts of changes to interchange schedules over the forward scheduling horizon in a manner that is consistent with the method used to establish Day-Ahead power flows over these facilities. Expected flows over the NYISO's other interconnections will be determined based on the current flow, modified to reflect the expected incremental impacts of changes to interchange schedules over the forward scheduling horizon, and shall be consistent with shift factors and delivery factors calculated in accordance with Section 17.1.1.1, above.

17.1.1.1.3 Scheduled Lines and Chateauguay Interconnection with Hydro Quebec

For purposes of scheduling and pricing, the NYISO expects that power flows will ordinarily match the interchange schedule at Scheduled Lines, and at the NYCA's Chateauguay interconnection with Hydro Quebec, in both the Day-Ahead and Real-Time Markets.

17.1.1.2 Incremental Dispatch Costs for Pricing Fast-Start Resources

For the purpose of calculating LBMPs for the Day-Ahead and Real-Time Markets, the incremental dispatch costs of Fast-Start Resources that Bid ISO-Committed Flexible shall be adjusted to include start-up costs and minimum generation costs based on the Start-Up Bids and Minimum Generation Bids or mitigated Start-Up Bids and Minimum Generation Bids of each such Resource ("Adjusted Dispatch Costs"). For start-up costs, the ISO will use a Fast-Start

Resource's single point Start-Up Bid if one is submitted (or the mitigated Bid, where appropriate). If a Fast-Start Resource does not submit a single point Start-Up Bid in the Real-Time Market, the ISO will use the point on the Fast-Start Resource's multi-point Start-Up Bid curve (or its mitigated multi-point Start-Up Bid curve, where appropriate) that corresponds to the shortest specified down time.

The ISO will use the following procedure to determine a Fast-Start Resource's Adjusted Dispatch Costs for each pricing interval in the Day-Ahead and Real-Time Markets. The ISO will determine the "cost-minimizing output level" that minimizes the average as-Bid operating cost ("minimum average cost") for that Fast-Start Resource in each hour of the Day-Ahead Market and in each RTD interval of the Real-Time Market. The average as-Bid operating cost for a Fast-Start Resource at a given operating level shall include the Fast-Start Resource's minimum generation costs and incremental energy costs to provide Energy at that operating level, based on the Resource's Bids, or mitigated Bids as appropriate. The average as-Bid operating cost may also include some or all of the Fast-Start Resource's start-up costs based on the Resource's Bids, or mitigated Bids as appropriate, in a given hour, to be determined as follows: (1) for the Day-Ahead Market, a Fast-Start Resource's average as-Bid operating cost to operate in a given hour will include start-up costs for the hour the Resource is scheduled to start; or (2) for the Real-Time Market, a Fast-Start Resource's average as-Bid operating cost to operate in a given RTD interval will include the start-up costs for approximately the first fifteen minutes, among consecutive operating intervals, after the Resource is scheduled to start, *i.e.*, for each RTD interval that starts within the first fifteen minutes after the Resource is scheduled to start, the average as-Bid operating cost to operate in that interval will include start-up costs.

For all output levels less than or equal to the cost-minimizing output level, the ISO will set the Adjusted Dispatch Cost equal to the minimum average cost. For all output levels greater than the cost-minimizing output level, the ISO will set the Adjusted Dispatch Cost equal to the price on the Resource's Bid curve. The ISO will calculate Adjusted Dispatch Costs for each output level between the Fast-Start Resource's minimum operating level and its UOL_N or UOL_E (whichever is applicable).

For the purpose of calculating LBMPs for the Day-Ahead and Real-Time Markets, all Fast-Start Resources that Bid ISO-Committed Flexible are treated as flexible and able to be dispatched anywhere between zero (0) MW and their UOL_N or UOL_E (whichever is applicable).

Additional rules for Fixed Block Units are set forth below in Section 17.1.2.1.2.

17.1.2 Real-Time LBMP Calculation Procedures

For each RTD interval, the ISO shall use the procedures described below in Sections 17.1.2.1-17.1.2.1.4 to calculate Real-Time LBMPs at each Load Zone and Generator bus. The LBMP bus and zonal calculation procedures are described in Sections 17.1.1 and 17.1.5 of this Attachment B, respectively. Procedures governing the calculation of LBMPs at Proxy Generator Buses are set forth below in Section 17.1.6 of this Attachment B.

17.1.2.1 General Procedures

17.1.2.1.1 Overview

The ISO shall calculate Real-Time Market LBMPs using the three passes of each RTD run, except as noted below in Section 17.1.2.1.3. A new RTD run will initialize every five minutes and each run will produce prices and schedules for five points in time (the optimization period). Only the prices and schedules determined for the first time point of the optimization period will be binding. Prices and schedules for the other four time points of the optimization period are advisory.

Each RTD run shall, depending on when it occurs during the hour, have a bid optimization horizon of fifty, fifty-five, or sixty minutes beyond the first, or binding, point in time that it addresses. The posting time and the first time point in each RTD run, which establishes binding prices and schedules, will be five minutes apart. The remaining points in time in each optimization period can be either five, ten, or fifteen minutes apart depending on when the run begins within the hour. The points in time in each RTD optimization period are arranged so that they parallel as closely as possible RTC's fifteen minute evaluations.

For example, the RTD run that posts its results at the beginning of an hour ("RTD_0") will initialize at the fifty-fifth minute of the previous hour and produce schedules and prices over a fifty-five minute optimization period. RTD_0 will produce binding prices and schedules for the RTD interval beginning when it posts its results (i.e., at the beginning of the hour) and ending at the first time point in its optimization period (i.e., five minutes after the hour). It will produce advisory prices and schedules for its second time point, which is ten minutes after the first time point in its optimization period, and advisory prices and schedules for its third, fourth and fifth time points, each of which would be fifteen minutes apart. The RTD run that posts its results at five minutes after the beginning of the hour ("RTD_5") will initialize at the beginning of the hour and produce prices over a fifty minute optimization period. RTD_5 will produce binding prices and schedules for the RTD interval beginning when it posts its results (i.e., at five minutes after the hour) and ending at the first time point in its optimization period (i.e., ten minutes after the hour.) It will produce advisory prices and schedules for its second time point (which is five minutes after the first time point), and advisory prices and schedules for its third, fourth and fifth time points, each of which would be fifteen minutes apart. The RTD run that posts its results at ten minutes after the beginning of the hour ("RTD_{10}") will initialize at five minutes after the beginning of the hour and produce prices over a sixty minute optimization period. RTD_{10} will produce binding prices and schedules for the interval beginning when it posts its results (i.e., at ten minutes after the hour) and ending at the first time point in its optimization period (i.e., fifteen minutes after the hour.) It will produce advisory prices and schedules for its second, third, fourth and fifth time points, each of which would be fifteen minutes after the preceding time point.

17.1.2.1.2 Description of the Real-Time Dispatch Process

17.1.2.1.2.1 The First Pass

The first RTD pass consists of a least bid cost, multi-period co-optimized dispatch for Energy, Regulation Service and Operating Reserves that treats all Fixed Block Units that are committed by RTC, or are otherwise instructed to be online or remain online by the ISO as if they were blocked on at their UOL_N or UOL_E, whichever is applicable. Fixed Block Units meeting Minimum Generation Levels and capable of being started in ten minutes that have not been committed by RTC are treated as flexible (i.e. able to be dispatched anywhere between zero (0) MW and their UOL_N or UOL_E, whichever is applicable). The first pass establishes "physical base points" (i.e., real-time Energy schedules) and real-time schedules for Regulation Service and Operating Reserves for the first time point of the optimization period. Physical base points and schedules established for the first time point shall be binding and shall remain in effect until the results of the next run are posted. Physical base points and schedules established for all subsequent time points shall be advisory. The first pass also produces information that is used to calculate the RTD Base Point Signals that the ISO sends to Suppliers.

When establishing physical base points, the ISO shall assume that each Generator will move toward the physical base point established during the first pass of the prior RTD run at its specified response rate.

17.1.2.1.2.1.1 Upper and Lower Dispatch Limits for Dispatchable Resources Other Than Intermittent Power Resources That Depend on Wind or Solar Energy as Their Fuel

When setting physical base points for a Dispatchable Resource at the first time point, the ISO shall ensure that they do not fall outside of the bounds established by the Dispatchable Resource's lower and upper dispatch limits. A Dispatchable Resource's dispatch limits shall be determined based on whether it was feasible for it to reach the physical base point calculated by the last RTD run given its: (A) metered output level and metered Energy Level (if applicable) at the time that the RTD run was initialized; (B) response rate; (C) minimum generation level/LOL; (D) USL and LSL (if applicable); and (E) UOL_N or UOL_E, whichever is applicable. If it was feasible for the Dispatchable Resource to reach that base point, then its upper and lower dispatch limits shall reflect the highest and lowest output levels it could achieve over the next RTD interval starting from its previous base point, subject to factors (A) through (E) specified above. If it was not feasible for the Dispatchable Resource to reach that base point, then its upper and lower dispatch limits shall reflect the highest and lowest output levels it could achieve over the next RTD interval, subject to factors (A) through (E) specified above, but instead starting from the feasible output level closest to its previous base point.

When setting physical base points for a Dispatchable Resource at later time points, the ISO shall ensure that they do not fall outside of the bounds established by the Resource's lower and upper dispatch limits for that time point. A Resource's dispatch limits at later time points shall be based on its: (A) dispatch limits from the first time point; (B) response rate; (C) minimum generation level/LOL; (D) Energy Level, USL and LSL (if applicable); and (E) UOL_N or UOL_E, whichever is applicable.

The upper dispatch limit for a Dispatchable Resource at later time points shall be determined by adjusting the upper dispatch limit from the first time point at the Resource's response rate, up to its UOL_N or UOL_E, whichever is applicable, considering Energy Level limitations for ISO-Managed ESRs. The lower dispatch limit for a Dispatchable Resource at later time points shall be determined by adjusting the lower dispatch limit from the first time point at the Resource's response rate, down to its minimum generation level/LOL considering applicable Energy Level limitations for ISO-Managed ESRs, or to a Demand Side Resource's Demand Reduction level.

The RTD Base Point Signals sent to Dispatchable Resources shall be the same as the physical base points determined above.

17.1.2.1.2.1.2 Upper and Lower Dispatch Limits for Intermittent Power Resources That Depend on Wind or Solar Energy as Their Fuel

For all time points of the optimization period, the Lower Dispatch Limit shall be the higher of (a) an Intermittent Power Resource's metered output level at the time that the RTD run was initialized reduced by its response rate, or (b) zero. The Upper Dispatch Limit shall be the Wind and Solar Energy Forecast for that Resource. For Intermittent Power Resources depending on wind as their fuel in commercial operation as of January 1, 2002 with a name plate capacity of 12 MWs or fewer, the Upper and Lower Dispatch Limits shall be the output level specified by the Wind and Solar Energy Forecast.

17.1.2.1.2.1.3. Setting Physical Basepoints for Fixed Generators

When setting physical base points for Self-Committed Fixed Generators in any time point, the ISO shall consider the feasibility of the Resource reaching the output levels that it specified in its self-commitment request for each time point in the RTD run given: (A) its metered output at the time that the run was initialized; and (B) its response rate.

When setting physical base points for ISO-Committed Fixed Generators in any time point, the ISO shall consider the feasibility of the Resource reaching the output levels scheduled for it by RTC for each time point in the RTD run given: (A) its metered output at the time that the run was initialized; and (B) its response rate.

The RTD Base Point Signals sent to Self-Committed Fixed Generators shall follow the quarter hour operating schedules that those Generators submitted in their real-time self-commitment requests.

The RTD Base Point Signals sent to ISO-Committed Fixed Generators shall follow the quarter hour operating schedules established for those Generators by RTC, regardless of their actual performance. To the extent possible, the ISO shall honor the response rates specified by such Generators when establishing RTD Base Point Signals. If a Self-Committed Fixed Generator's operating schedule is not feasible based on its real-time self-commitment requests then its RTD Base Point Signals shall be determined using a response rate consistent with the operating schedule changes.

17.1.2.1.2.2 The Second Pass

The second RTD pass consists of a least bid cost, multi-period, co-optimized dispatch for Energy, Regulation Service, and Operating Reserves that treats: (i) all Fast-Start Resources that are committed by RTC; (ii) all Fixed Block Units meeting Minimum Generation Levels and capable of starting in ten minutes that have not been committed by RTC; and (iii) all Fixed Block Units otherwise instructed to be online or remain online by the ISO, as flexible (i.e., able to be dispatched anywhere between zero (0) MW and their UOL_N or UOL_E, whichever is applicable), regardless of their minimum run-time status. The second pass calculates real-time Energy prices and real-time Shadow Prices for Regulation Service and Operating Reserves that the ISO shall use for settlement purposes pursuant to Section 4, Rate Schedule 15.3, and Rate Schedule 15.4 of this ISO Services Tariff respectively. The ISO will not use schedules for Energy, Regulation Service and Operating Reserves established in the second pass to dispatch Resources.

The upper and lower dispatch limits used for ISO-Committed Fixed and Self-Committed Fixed Resources shall be the same as the physical base points calculated in the first pass.

17.1.2.1.2.2.1 Upper and Lower Dispatch Limits for Dispatchable Resources Other Than Intermittent Power Resources That Depend on Wind or Solar Energy as Their Fuel

The upper dispatch limit for the first time point of the second pass for a Dispatchable Resource shall be the higher of: (A) its upper dispatch limit from the first pass; or (B) its "pricing base point" from the first time point of the prior RTD interval adjusted up within its Dispatchable range for any possible ramping since that pricing base point was issued less the higher of: (i) the physical base point established during the first pass of the RTD immediately prior to the previous RTD minus the Resource's metered output level at the time that the current RTD run was initialized, or (ii) zero.

The lower dispatch limit for the first time point of the second pass for a Dispatchable Resource shall be the lower of: (A) its lower dispatch limit from the first pass; or (B) its "pricing base point" from the first time point of the prior RTD interval adjusted down within its Dispatchable range to account for any possible ramping since that pricing base point was issued plus the higher of: (i) the Resource's metered output level at the time that the current RTD run was initialized minus the physical base point established during the first pass of the RTD immediately prior to the previous RTD, considering the metered Energy Level if applicable; or (ii) zero.

The upper dispatch limit for the later time points of the second pass for a Dispatchable Resource shall be determined by adjusting its upper dispatch limit from the first time point at the Resource's response rate, up to its UOL_N or UOL_E, whichever is applicable, considering Energy Level limitations for ISO-Managed ESRs. The lower dispatch limit for the later time points of the second pass for a Dispatchable non-Fast-Start Resource shall be determined by adjusting its lower dispatch limit from the first time point at the Resource's response rate, down to its minimum generation level/LOL, considering Energy Level limitations for ISO-Managed ESRs. The lower dispatch limit for the later time points of the second pass for a Fast Start Resource shall be determined by decreasing its lower dispatch limit from the first time point at the Resource's response rate, down to zero.

17.1.2.1.2.2.2 Upper and Lower Dispatch Limits for Intermittent Power Resources That Depend on Wind or Solar Energy as Their Fuel

For the first time point and later time points for Intermittent Power Resources that depend on wind or solar energy as their fuel, the Lower Dispatch Limit shall be zero and the Upper Dispatch Limit shall be the Wind and Solar Energy Forecast for that Resource. For Intermittent Power Resources depending on wind as their fuel in commercial operation as of January 1, 2002 with a name plate capacity of 12 MWs or fewer, the Upper and Lower Dispatch Limits shall be the output level specified by the Wind and Solar Energy Forecast.

17.1.2.1.2.3 The Third Pass

The third RTD pass is reserved for future use.

17.1.2.1.3 Variations in RTD-CAM

When the ISO activates RTD-CAM, the following variations to the rules specified above in Sections 17.1.2.1.1 and 17.1.2.1.2 shall apply.

First, if the ISO enters reserve pickup mode: (i) the ISO will produce prices and schedules for a single ten minute interval (not for a multi-point co-optimization period); (ii) the ISO shall set Regulation Service schedules to zero as described in Rate Schedule 15.3 of this ISO Services Tariff; (iii) the ISO will have discretion to make additional Generator commitments before executing the three RTD passes; and (iv) the ISO will have discretion to allow the RTD Base Point Signal of each Dispatchable Generator to be set to the higher of the Generator's physical base point or its actual generation level.

Second, if the ISO enters maximum generation pickup mode: (i) the ISO will produce prices and schedules for a single five minute interval (not for a multi-point co-optimization period); (ii) the ISO shall set Regulation Service schedules to zero as described in Rate Schedule 15.3 of this ISO Services Tariff; (iii) the ISO will have discretion to make additional Generator commitments in the affected area before executing the three RTD passes; and (iv) the ISO will have discretion to either move the RTD Base Point Signal of each Generator within the affected area towards its UOL_E at its emergency response rate or set it at a level equal to its physical base point.

Third, if the ISO enters basepoints ASAP – no commitments mode it will produce prices and schedules for a single five minute interval (not for a multi-point co-optimization period).

Fourth, if the ISO enters basepoints ASAP – commit as needed mode: (i) the ISO will produce price and schedules for a single five minute interval (not for a multi-point co-optimization period); and (ii) the ISO may make additional commitments of Generators that are capable of starting within ten minutes before executing the three RTD passes.

Fifth, and finally, if the ISO enters re-sequencing mode it will solve for a ten-minute optimization period consisting of two five-minute time points.

17.1.2.1.4 The Real-Time Commitment ("RTC") Process and Automated Mitigation

Attachment H of this Services Tariff shall establish automated market power mitigation measures that may affect the calculation of Real-Time LBMPs. To the extent that these measures are implemented they shall be incorporated into the RTC software through the establishment of a second, parallel, commitment evaluation that will assess the impact of the mitigation measures. The first evaluation, referred to as the "RTC evaluation," will determine the schedules and prices that would result using an original set of offers and Bids before any additional mitigation measures, the necessity for which will be considered in the RTC evaluation, are applied. The second evaluation, referred to as the "RT-AMP" evaluation, will determine the schedules and prices that would result from using the original set of offers and bids as modified by any necessary mitigation measures. Both evaluations will follow the rules governing RTC's operation that are set forth in Section 4 of and this Attachment B to this ISO Services Tariff.

In situations where Attachment H specifies that real-time automated mitigation measures be utilized, the ISO will perform the two parallel RTC evaluations in a manner that enables it to implement mitigation measures one RTC run (i.e., fifteen minutes) in the future. For example, RTC_{15} and $RT\text{-}AMP_{15}$ will perform Resource commitment evaluations simultaneously. RT-

AMP_{15} will then apply the mitigation “impact” test, account for reference bid levels as appropriate and determine which Resources are actually to be mitigated. This information will then be conveyed to RTC_{30} which will make Resource commitments consistent with the application of the mitigation measures (and will thus indirectly be incorporated into future RTD runs).

17.1.3 Day-Ahead LBMP Calculation Procedures

LBMPs in the Day-Ahead Market are calculated using five passes. The first two passes are commitment and dispatch passes; the last three are dispatch only passes.

Pass 1 consists of a least cost commitment and dispatch to meet Bid Load and reliable operation of the NYS Power System that includes Day-Ahead Reliability Units.

It consists of several steps. Step 1A is a complete Security Constrained Unit Commitment (“SCUC”) to meet Bid Load. At the end of this step, committed Fast-Start Resources, Imports, Exports, Virtual Supply, Virtual Load, Demand Side Resources and non-Fast-Start Resources are dispatched to meet Bid Load. Fast-Start Resources are treated as dispatchable between zero MW and their UOL_N or UOL_E, whichever is applicable. For mitigation purposes, LBMPs are calculated from this dispatch. Following Step 1A, SCUC tests for automated mitigation procedure (“AMP”) activation.

If AMP is activated, Step 1B tests to determine if the AMP will be triggered by mitigating offer prices subject to mitigation that exceed the conduct threshold to their respective reference prices. These mitigated offer prices together with all originally submitted offer prices not subject to automatic mitigation are then used to commit generation and dispatch energy to meet Bid Load. This step is another iteration of the SCUC process. At the end of Step 1B, committed Fast-Start Resources, Imports, Exports, Virtual Supply, Virtual Load, Demand Side

Resources, and non-Fast-Start Resources are again dispatched to meet Bid Load using the same mitigated or unmitigated Bids used to determine the commitment to meet Bid Load. Fast-Start Resources are treated as dispatchable between zero MW and their UOL_N or UOL_E, whichever is applicable. For mitigation purposes, LBMPs are again calculated from this dispatch. The LBMPs determined at the end of Step 1B are compared to the LBMPs determined at the end of Step 1A to determine the hours and zones in which the impact test is met.

In Step 1C, generation offer prices subject to mitigation that exceed the conduct threshold are mitigated for those hours and zones in which the impact test was met in Step 1B. The mitigated offer prices, together with the original unmitigated offer price of units whose offer prices were not subject to mitigation, or did not trigger the conduct or impact thresholds, are used to commit generation and dispatch energy to meet Bid Load. This step is also a complete iteration of the SCUC process. At the end of Step 1C, committed Fast-Start Resources, Imports, Exports, virtual supply, virtual load, Demand Side Resources, and non- Fast-Start Resources are again dispatched to meet Bid Load. Fast-Start Resources are treated as dispatchable between zero MW and their UOL_N or UOL_E, whichever is applicable. For mitigation purposes, LBMPs are again calculated from this dispatch.

All Demand Side Resources and non-Fixed Block Units committed in the final step of Pass 1 (which could be either step 1A, 1B, or 1C depending on activation of the AMP) are blocked on at least to minimum generation level in Passes 4 through 6. All Energy Storage Resources dispatched in the final step of Pass 1 (which could be either Step 1A, 1B, or 1C depending on activation of the AMP) are blocked on at the dispatch that was determined in Pass 1 in Passes 2 through 4. The resources required to meet local system reliability are determined in Pass 1.

Pass 2 consists of a least cost commitment and dispatch of Fast-Start Resources, Imports, Exports, Demand Side Resources and non- Fast-Start Resources to meet forecast Load requirements in excess of Bid Load, considering the Wind and Solar Energy Forecast, that minimizes the cost of incremental Minimum Generation and Start Up Bids, given revenues for Minimum Generation Energy based on LBMPs calculated in Pass 1, and assumes all Fast-Start Resources are dispatchable between zero MW and their UOL_N or UOL_E, whichever is applicable. Incremental Import Capacity needed to meet forecast Load requirements is determined in Pass 2. Fixed Block Units committed in this pass are not included in the least cost dispatches of Passes 5 or 6. Demand Side Resources and non-Fixed Block Units committed in this step are blocked on at least to minimum generation level in Passes 4 through 6. Intermittent Power Resources that depend on wind or solar energy as their fuel committed in this pass as a result of the consideration of the Wind and Solar Energy Forecast are not blocked in Passes 5 or 6.

Pass 3 is reserved for future use.

Pass 4 consists of a least cost dispatch to forecast Load. It is not used to set schedules or prices. It is used for operational purposes and provides a dispatch of Fast-Start Resources, Imports, Exports, Demand Side Resources and non- Fast-Start Resources committed in Passes 1 or 2. Incremental Import Capacity committed in Pass 2 is re-evaluated and may be reduced if no longer required.

Pass 5 consists of a least cost dispatch of Fast-Start Resources, Imports, Exports, Virtual Supply, Virtual Load, Demand Side Resources and non- Fast-Start Resources committed to meet Bid Load, based where appropriate on offer prices as mitigated in Pass 1. Fast-Start Resources are treated as dispatchable between zero MW and their UOL_N or UOL_E, whichever is applicable.

LBMPs used to settle the Day-Ahead Market are calculated from this dispatch. The Shadow Prices used to compute Day-Ahead Market clearing prices for Regulation Service and for Operating Reserves in Rate Schedules 3 and 4 of this ISO Services Tariff are also calculated from this dispatch. Final schedules for all Imports, Exports, Virtual Supply, Virtual Load, Demand Side Resources and non-Fixed Block Units in the Day-Ahead Market are calculated from this dispatch.

Pass 6 consists of a least cost dispatch of all Day-Ahead committed Resources, Imports, Exports, Virtual Supply, Virtual Load, based where appropriate on offer prices as mitigated in Pass 1, with the schedules of all Fixed Block Units committed in the final step of Pass 1 blocked on at maximum Capacity. Final schedules for Fixed Block Units in the Day-Ahead Market are calculated from this dispatch.

17.1.4 Determination of Transmission Shortage Cost

The applicable Transmission Shortage Cost depends on whether a particular transmission Constraint is associated with a transmission facility or Interface that includes a non-zero constraint reliability margin value. The ISO shall establish constraint reliability margin values for transmission facilities and Interfaces. Non-zero constraint reliability margin values established by the ISO are normally equal to 20 MW. The ISO shall post to its website a list of transmission facilities and Interfaces assigned a constraint reliability margin value other than 20 MW.

For transmission facilities and Interfaces with a non-zero constraint reliability margin value, SCUC, RTC and RTD shall include consideration of a two step demand curve consisting of up to an additional 5 MW of available resource capacity at a cost of $350/MWh and up to an additional 15 MW of available resource capacity at a cost of $1,175/MWh when evaluating transmission Constraints associated with such facilities and Interfaces. In no event, however, shall the Shadow Price for such transmission Constraints exceed $4,000/MWh.

For transmission facilities and Interfaces with a constraint reliability margin value of zero, the Shadow Price for transmission Constraints associated with such facilities and Interfaces shall not exceed $4,000/MWh. SCUC, RTC and RTD shall not include consideration of the available resource capacity provided by the two step demand curve described above for such transmission Constraints.

In evaluating all transmission Constraints, the ISO will determine whether sufficient available resource capacity exists to solve each transmission Constraint at its applicable limit. If sufficient available resource capacity does not exist to solve the transmission Constraint at its otherwise applicable limit, the ISO shall increase the applicable limit for such transmission Constraint to an amount achievable by the available resource capacity plus 0.2 MW. For transmission facilities and Interfaces with a non-zero constraint reliability margin value, the ISO shall account for the 20 MW of available resource capacity from the two step demand curve described above in determining: (i) whether sufficient available resource capacity exists to solve transmission Constraints associated with such facilities and Interfaces at their otherwise applicable limit; and (ii) the extent of any limit adjustment required to solve such transmission Constraints.

The ISO may periodically evaluate the Transmission Shortage Cost to determine whether it is necessary to modify the Transmission Shortage Cost to avoid future operational or reliability problems. The ISO will consult with its Market Monitoring Unit after it conducts this evaluation. If the ISO determines that it is necessary to modify the Transmission Shortage Costs in order to avoid future operational or reliability problems the resolution of which would otherwise require recurring operator intervention outside normal market scheduling procedures, in order to avoid among other reliability issues, a violation of NERC Interconnection Reliability Operating Limits or System Operating Limits, it may temporarily modify it for a period of up to ninety days, provided however the NYISO shall file such change with the Commission pursuant to Section 205 of the Federal Power Act within 45 days of such modification. If circumstances reasonably allow, the ISO will consult with its Market Monitoring Unit, the Business Issues Committee, the Commission, and the PSC before implementing any such modification. In all circumstances, the ISO will: (i) consult with those entities as soon as reasonably possible after implementing a temporary modification and shall explain the reasons for the change; and (ii) notify Market Participants of any temporary modification.

The responsibilities of the ISO and the Market Monitoring Unit in evaluating and modifying the Transmission Shortage Cost, as necessary are addressed in Attachment O, Section 30.4.6.8.1 of this Market Services Tariff ("Market Monitoring Plan").

17.1.5 Zonal LBMP Calculation Method

The computation described in Section 17.1.1 of this Attachment B is at the bus level. An eleven (11) zone model will be used for the LBMP billing related to Loads, except for Energy withdrawals by Eligible Generators for later injection onto the grid. The LBMP for a zone will be a Load weighted average of the Load bus LBMPs in the Load Zone. The Load weights which will sum to unity will be calculated from the load bus MW distribution. Each component of the LBMP for a zone will be calculated as a Load weighted average of the Load bus LBMP components in the zone. The LBMP for a zone *j* can be written as:

$$\gamma_j^Z = \lambda^R + \gamma_j^{L,Z} + \gamma_j^{C,Z}$$

where:

$\gamma_j^Z =$	LBMP for zone j,
$\gamma_j^{L,Z} = \sum_{i=1}^{n} W_i \gamma_i^L$	is the Marginal Losses Component of the LBMP for zone j;
$\gamma_j^{C,Z} = \sum W_i \gamma_i^L$	is the Congestion Component of the LBMP for zone j;
$n =$	number of Load buses in zone j for which LBMPs are calculated; and
$W_i =$	Load weighting factor for bus i.

The NYISO also calculates and posts zonal LBMP for four (4) external zones for informational purposes only. Settlements for External Transactions are determined using the Proxy Generator Bus LBMP. Each external zonal LBMP is equal to the LBMP of the Proxy Generator Bus associated with that external zone. The table below identifies which Proxy Generator Bus LBMP is used to determine each of the posted external zonal LBMPs.

External Zone	External Zone PTID	Proxy Generator Bus	Proxy Generator Bus PTID
HQ	61844	HQ_GEN_WHEEL	23651
NPX	61845	N.E._GEN_SANDY_POND	24062
OH	61846	O.H._GEN_PROXY	24063
PJM	61847	PJM_GEN_KEYSTONE	24065

Consistent with the ISO Services Tariff**,** LBMPs at Proxy Generator Buses are determined using calculated bus prices as described in this Section 17.1.

17.1.6 Real Time LBMP Calculation Methods for Proxy Generator Buses, Non-Competitive Proxy Generator Buses and Proxy Generator Buses Associated with Designated Scheduled Lines

17.1.6.1 Definitions

Interface ATC Constraint: An Interface ATC Constraint exists when proposed economic transactions over an Interface between the NYCA and the Control Area with which one or more Proxy Generator Bus(es) are associated would exceed the transfer capability for the Interface or for an associated Proxy Generator Bus.

Interface Ramp Constraint: An Interface Ramp Constraint exists when proposed interchange schedule changes pertaining to an Interface between the NYCA and the Control Area with which one or more Proxy Generator Bus(es) are associated would exceed any Ramp Capacity limit imposed by the ISO for the Interface or for an associated Proxy Generator Bus.

NYCA Ramp Constraint: A NYCA Ramp Constraint exists when proposed interchange schedule changes pertaining to the NYCA as a whole would exceed any Ramp Capacity limits in place for the NYCA as a whole.

Proxy Generator Bus Constraint: Any of an Interface ATC Constraint, an Interface Ramp Constraint, or a NYCA Ramp Constraint (individually and collectively).

External Interface Congestion: The product of: (i) the portion of the Congestion Component of the LBMP at a Proxy Generator Bus that is associated with a Proxy Generator Bus Constraint and (ii) a factor, between zero and 1, calculated pursuant to ISO Procedures.

Proxy Generator Bus Border LBMP: The LBMP at a Proxy Generator Bus minus External Interface Congestion at that Proxy Generator Bus.

Unconstrained RTD LBMP: The LBMP as calculated by RTD less any congestion associated with a Proxy Generator Bus Constraint.

17.1.6.2 General Rules

Transmission Customers and Customers with External Generators and Loads can bid into the LBMP Market or participate in Bilateral Transactions. Those with External Generators may arrange LBMP Market sales and/or Bilateral Transactions with Internal or External Loads and External Loads may arrange LBMP Market purchases and/or Bilateral Transactions with Internal Generators.

The Generator and Load locations for which LBMPs will be calculated will initially be limited to a pre-defined set of Proxy Generator Buses. LBMPs will be calculated for each Proxy

Generator Bus within this limited set. When an Interface with multiple Proxy Generator Buses is constrained, the ISO will apply the constraint to all of the Proxy Generator Buses located at that Interface. Except as set forth in Sections 17.1.6.3 and 17.1.6.4, the NYISO will calculate the three components of LBMP for Transactions at a Proxy Generator Bus as provided in the tables below.

When determining the External Interface Congestion, if any, to apply to determine the LBMP for RTD intervals that bridge two RTC intervals, the NYISO shall use the External Interface Congestion associated with the second (later) RTC interval.

17.1.6.2.1 Pricing rules for Dynamically Scheduled Proxy Generator Buses

The pricing rules for Dynamically Scheduled Proxy Generator Buses are to be determined.

17.1.6.2.2 Pricing rules for Variably Scheduled Proxy Generator Buses

The pricing rules for Variably Scheduled Proxy Generator Buses are provided in the following table.

Rule No.	Proxy Generator Bus Constraint affecting External Schedules at location *a*	Direction of Proxy Generator Bus Constraint	Real-Time Pricing Rule (for location *a*)
1	Unconstrained in RTC_{15}, Rolling RTC and RTD	N/A	Real-Time $LBMP_a$ = RTD $LBMP_a$
2	The Rolling RTC used to schedule External Transactions in a given 15-minute interval is subject to a Proxy Generator Bus Constraint	Into NYCA or out of NYCA (Import or Export)	Real-Time $LBMP_a$ = RTD $LBMP_a$ + Rolling RTC External Interface $Congestion_a$

17.1.6.2.3 Pricing rules for Proxy Generator Buses that are not Dynamically Scheduled or Variably Scheduled

The pricing rules for Proxy Generator Buses that are not Dynamically Scheduled or Variably Scheduled Proxy Generator Buses are provided in the following table.

Rule No.	Proxy Generator Bus Constraint affecting External Schedules at location *a*	Direction of Proxy Generator Bus Constraint	Real-Time Pricing Rule (for location *a*)
1	Unconstrained in RTC_{15}, Rolling RTC and RTD	N/A	Real-Time $LBMP_a$ = RTD $LBMP_a$
3	RTC_{15} is subject to a Proxy Generator Bus Constraint	Into NYCA or out of NYCA (Import or Export)	Real-Time $LBMP_a$ = RTD $LBMP_a$ + RTC_{15} External Interface $Congestion_a$

17.1.6.3 Rules for Non-Competitive Proxy Generator Buses and Associated Interfaces

Real-Time LBMPs for an Interface that is associated with one or more Non-Competitive Proxy Generator Buses or for a Non-Competitive Proxy Generator Bus shall be determined as provided in the tables below. Non-Competitive Proxy Generator Buses are identified in Section 4.4.4 of the Services Tariff.

17.1.6.3.1 Pricing rules for Non-Competitive, Dynamically Scheduled Proxy Generator Buses

The pricing rules for Non-Competitive, Dynamically Scheduled Proxy Generator Buses are to be determined.

17.1.6.3.2 Pricing rules for Non-Competitive, Variably Scheduled Proxy Generator Buses

The pricing rules for Non-Competitive, Variably Scheduled Proxy Generator Buses are provided in the following table.

Rule No.	Proxy Generator Bus Constraint affecting External Schedules at location *a*	Direction of Proxy Generator Bus Constraint	Real-Time Pricing Rule (for location *a*)
1	Unconstrained in RTC_{15}, Rolling RTC and RTD	N/A	Real-Time $LBMP_a$ = RTD $LBMP_a$
4	The Rolling RTC used to schedule External Transactions in a given 15-minute interval is subject to an Interface ATC or Interface RampConstraint	Into NYCA (Import)	If Rolling RTC Proxy Generator Bus $LBMP_a > 0$, then Real-Time $LBMP_a$ = RTD $LBMP_a$ + Rolling RTC External Interface $Congestion_a$ Otherwise, Real-Time $LBMP_a$ = Minimum of (i) RTD $LBMP_a$ and (ii) zero
5	The Rolling RTC used to schedule External Transactions in a given 15-minute interval is subject to an Interface ATC or Interface Ramp Constraint	Out of NYCA (Export)	If Rolling RTC Proxy Generator Bus $LBMP_a < 0$, then Real-Time $LBMP_a$ = RTD $LBMP_a$ + Rolling RTC External Interface $Congestion_a$ Otherwise, Real-Time $LBMP_a$ = RTD $LBMP_a$

17.1.6.3.3 Pricing rules for Non-Competitive Proxy Generator Buses that are not Dynamically Scheduled or Variably Scheduled Proxy Generator Buses

The pricing rules for Non-Competitive Proxy Generator Buses that are not Dynamically Scheduled or Variably Scheduled Proxy Generator Buses are provided in the following table.

Rule No.	Proxy Generator Bus Constraint affecting External Schedules at location *a*	Direction of Proxy Generator Bus Constraint	Real-Time Pricing Rule (for location *a*)
1	Unconstrained in RTC_{15}, Rolling RTC and RTD	N/A	Real-Time $LBMP_a$ = RTD $LBMP_a$
6	RTC_{15} is subject to an Interface ATC or Interface Ramp Constraint	Into NYCA (Import)	If RTC_{15} Proxy Generator Bus $LBMP_a > 0$, then Real-Time $LBMP_a$ = RTD $LBMP_a$ + RTC_{15} External Interface $Congestion_a$ Otherwise, Real-Time $LBMP_a$ = Minimum of (i) RTD $LBMP_a$ and (ii) zero
7	RTC_{15} is subject to an Interface ATC or Interface Ramp Constraint	Out of NYCA (Export)	If RTC_{15} Proxy Generator Bus $LBMP_a < 0$, then Real-Time $LBMP_a$ = RTD $LBMP_a$ + RTC_{15} External Interface $Congestion_a$ Otherwise, Real-Time $LBMP_a$ = RTD $LBMP_a$

17.1.6.4 Special Pricing Rules for Proxy Generator Buses Associated with Designated Scheduled Lines

Real-Time LBMPs for the Proxy Generator Buses associated with designated Scheduled Lines shall be determined as provided in the tables below. The Proxy Generator Buses that are associated with designated Scheduled Lines are identified in Section 4.4.4 of the Services Tariff.

17.1.6.4.1 Pricing rules for Dynamically Scheduled Proxy Generator Buses that are associated with Designated Scheduled Lines

The pricing rules for Dynamically Scheduled Proxy Generator Buses that are associated with designated Scheduled Lines are to be determined.

17.1.6.4.2 Pricing rules for Variably Scheduled Proxy Generator Buses that are associated with Designated Scheduled Lines

The pricing rules for Variably Scheduled Proxy Generator Buses that are associated with designated Scheduled Lines are provided in the following table.

Rule No.	Proxy Generator Bus Constraint affecting External Schedules at location *a*	Direction of Proxy Generator Bus Constraint	Real-Time Pricing Rule (for location *a*)
1	Unconstrained in RTC_{15}, Rolling RTC and RTD	N/A	Real-Time $LBMP_a$ = RTD $LBMP_a$
4	The Rolling RTC used to schedule External Transactions in a given 15-minute interval is subject to an Interface ATC Constraint	Into NYCA (Import)	If Rolling RTC Proxy Generator Bus $LBMP_a$ > 0, then Real-Time $LBMP_a$ = RTD $LBMP_a$ + Rolling RTC External Interface $Congestion_a$ Otherwise, Real-Time $LBMP_a$ = Minimum of (i) RTD $LBMP_a$ and (ii) zero
5	The Rolling RTC used to schedule External Transactions in a given 15-minute interval is subject to an Interface ATC Constraint	Out of NYCA (Export)	If Rolling RTC Proxy Generator Bus $LBMP_a$ < 0, then Real-Time $LBMP_a$ = RTD $LBMP_a$ + Rolling RTC External Interface $Congestion_a$ Otherwise, Real-Time $LBMP_a$ = RTD $LBMP_a$)

17.1.6.4.3 Pricing rules for Proxy Generator Buses that are associated with Designated Scheduled Lines that are not Dynamically Scheduled or Variably Scheduled Proxy Generator Buses

The pricing rules for Proxy Generator Buses that are associated with designated Scheduled Lines that are not Dynamically Scheduled or Variably Scheduled Proxy Generator Buses, are provided in the following table.

Rule No.	Proxy Generator Bus Constraint affecting External Schedules at location *a*	Direction of Proxy Generator Bus Constraint	Real-Time Pricing Rule (for location *a*)
1	Unconstrained in RTC_{15}, Rolling RTC and RTD	N/A	Real-Time $LBMP_a$ = RTD $LBMP_a$
6	RTC_{15} is subject to an Interface ATC Constraint	Into NYCA (Import)	If RTC_{15} Proxy Generator Bus $LBMP_a$ > 0, then Real-Time $LBMP_a$ = RTD $LBMP_a$ + RTC_{15} External Interface $Congestion_a$ Otherwise, Real-Time $LBMP_a$ = Minimum of (i) RTD $LBMP_a$ and (ii) zero

Rule No.	Proxy Generator Bus Constraint affecting External Schedules at location *a*	Direction of Proxy Generator Bus Constraint	Real-Time Pricing Rule (for location *a*)
7	RTC_{15} is subject to an Interface ATC Constraint	Out of NYCA (Export)	If RTC_{15} Proxy Generator Bus $LBMP_a < 0$, then Real-Time $LBMP_a$ = RTD $LBMP_a$ + RTC_{15} External Interface $Congestion_a$ Otherwise, Real-Time $LBMP_a$ = RTD $LBMP_a$

17.1.6.5 Method of Calculating Marginal Loss and Congestion Components of Real-Time LBMP at Non-Competitive Proxy Generator Buses and Proxy Generator Buses that are Subject to the Special Pricing Rule for Designated Scheduled Lines

Under the conditions specified below, the Marginal Losses Component and the Congestion Component of the Real-Time LBMP, calculated pursuant to the preceding paragraphs in Sections 17.1.6.3 and 17.1.6.4, shall be constructed as follows:

When the Real-Time LBMP is set to zero and that zero price was not the result of using the RTD, RTC or SCUC-determined LBMP;

$$Marginal\ Losses\ Component\ of\ the\ Real\text{-}Time\ LBMP = Losses_{RTD\ PROXY\ GENERATOR\ BUS}$$

and

$$Congestion\ Component\ of\ the\ Real\text{-}Time\ LBMP = -(Energy_{RTD\ REF\ BUS} + Losses_{RTD\ PROXY\ GENERATOR\ BUS})$$

where:

$Energy_{RTD\ REF\ BUS}$ = The marginal Bid cost of providing Energy at the reference Bus, as calculated by RTD for that 5-minute interval; and

$Losses_{RTD\ PROXY\ GENERATOR\ BUS}$ = The Marginal Losses Component of the LBMP as calculated by RTD for that 5-minute interval at the Non-Competitive Proxy Generator Bus or Proxy Generator Bus associated with a designated Scheduled Line.

23.2 Conduct Warranting Mitigation

23.2.1 Definitions

The following definitions are applicable to this Attachment H:

For purposes of Section 23.4.5 of this Attachment H, "**Additional CRIS MW**" shall mean the MW of Capacity for which CRIS was requested for an Examined Facility pursuant to the provisions in ISO OATT Sections 25, 30, or 32 (OATT Attachments S, X, or Z), including either: (i) all, or a portion, of the MW of Capacity of that Examined Facility for which CRIS had not been obtained in prior Class Years through a prior Class Year process or through a transfer completed in accordance with OATT Section 25 (OATT Attachment S); and/or (ii) all, or a portion, of an increase in the Capacity of that Examined Facility. Additional CRIS MW does not include any MW quantity of CRIS that is exempt from an Offer Floor pursuant to Section 23.4.5.7.7(a) or (b), Section 23.4.5.7.8, or an increase of 2 MW or less in an Examined Facility's MW quantity of CRIS obtained pursuant to Section 30.3.2.6 of Attachment X to the OATT.

"**Additional SDU Study**" shall mean a deliverability study that a Developer may elect to pursue as that term is defined in OATT Section 25 (OATT Attachment S).

For purposes of Section 23.4.5 of this Attachment H, "**Affiliated Entity**" shall mean, with respect to a person or Entity:

i) all persons or Entities that directly or indirectly control such person or Entity;

ii) all persons or Entities that are directly or indirectly controlled by or under common control with such person or Entity, and (1) are authorized under ISO Procedures to participate in a market for Capacity administered by the ISO, or (2) possess, directly or indirectly, an ownership, voting or equivalent interest of ten percent or more in a Mitigated Capacity Zone Installed Capacity Supplier;

iii) all persons or Entities that provide services to such person or Entity, or for which such person or Entity provides services, if such services relate to the determination or submission of offers for Unforced Capacity in a market administered by the ISO or offers of capacity from a Generator electrically located in a MCZ Import Constrained Locality; or

iv) all persons or Entities, except if for ISP UCAP MW or an RMR Generator, with which such person or Entity has any form of agreement under which such person or Entity has retained or has conferred rights of (i) Control of Unforced Capacity or (ii) the ability to determine the quantity or price of offers to supply capacity from a Generator that has Capacity Resource Interconnection Service, pursuant to the applicable provisions of Attachment X, Attachment S and Attachment Z and is electrically located in an MCZ Import Constrained Locality, even if such capacity does not meet the requirements to be Unforced Capacity.

In the foregoing definition, “**control**” means the possession, directly or indirectly, of the power to direct the management or policies of a person or Entity, and shall be rebuttably presumed from an ownership, voting or equivalent interest of ten percent or more.

Catastrophic Failure: shall mean a Forced Outage initially suffered by a Generator which would have reasonably required a repair time of at least 270 days, from the date of the event resulting in the Forced Outage, had it, or a comparable Forced Outage been suffered at a generating facility that is reasonably the same as or similar to the Generator’s, the owner of which is intending to return it to service. Repair time includes the reasonable number of days for initial clean up, safety inspections, engineering assessment; damage assessment, cost estimates; site prep and clean up, equipment orders, and actual repair, provided the foregoing are necessitated by the Catastrophic Failure. The determination that a Generator has suffered a Catastrophic Failure shall be based on a technical/engineering evaluation, shall be made by the ISO, and may be made at any time following the event that caused the Forced Outage provided that adequate information is provided to the ISO to support such determination.

“**Class Year Study**” means a Class Year Interconnection Facilities Study as that term is defined in OATT Section 25 (OATT Attachment S).

“**Cleared UCAP**” means the amount of MW (rounded down to the nearest tenth of a MW) that had been subject to an Offer Floor but has cleared in accordance with Section 23.4.5.7.

“**Commenced Construction**” shall mean (a) all of the following site preparation work is completed: ingress and egress routes exist; the site on which the Project will be located is cleared and graded; there is power service to the site; footings are prepared; and foundations have been poured consistent with purchased equipment specifications and project design; or (b) the following financial commitments have been made: (i) (A) an engineering, procurement, and construction contract (“EPC”) has been executed by all parties and is effective; or (B) contracts (collectively, “EPC Equivalents”) for all of the following have been executed by all parties and is effective: (1) project engineering, (2) procurement of all major equipment, and (3) construction of the Project, and (ii) the cumulative payments made by the Developer under the EPC or EPC Equivalents to the counterparties to those respective agreements is equal to at least thirty (30) percent of the total costs of the EPC or EPC Equivalents.

“**Competitive and Non-Discriminatory Hedging Contract**” shall mean a contract to hedge a risk associated with a product offered in the ISO Administered Markets between a Non-Qualifying Entry Sponsor and the Developer, Owner or Operator of an Examined Facility with a term that shall not exceed three years (inclusive of all options to extend and extensions) and that the ISO determines has been executed pursuant to a procurement process that satisfies the requirements enumerated below. Competitive and Non-Discriminatory Hedging Contracts shall not be deemed to be a non-qualifying contractual relationship that would prevent an Examined Facility from obtaining a Competitive Entry Exemption pursuant to 23.4.5.7.9 of Attachment H of this Services Tariff. The ISO shall determine that a contract is a Competitive and Non-Discriminatory Hedging Contract only if it concludes, and the Non-Qualifying Entry Sponsor executes a certification confirming that, the contract was executed through a procurement process that met all of the following requirements: (A) both new and existing resources satisfy the requirements of the procurement; (B) the requirements of the procurement were fully objective and transparent ; (C) the contract was awarded based on the lowest cost offers of qualified bidders that responded to the solicitation; (D) the procurement terms did not restrict the type of capacity resources that may participate in, and satisfy the requirements of, the procurement; (E) the procurement terms did not include selection criteria that could otherwise give preference to new resources; and (F) the procurement terms did not use indirect means to discriminate against existing resources, including, but not limited to, by imposing geographic constraints, unit fuel requirements, maximum unit heat-rate requirements or requirements for new construction.

"**Constrained Area**" shall mean: (a) the In-City area, including any areas subject to transmission constraints within the In-City area that give rise to significant locational market power; and (b) any other area in the New York Control Area that has been identified by the ISO as subject to transmission constraints that give rise to significant locational market power, and that has been approved by the Commission for designation as a Constrained Area.

For purposes of Section 23.4.5 of this Attachment H, "**Control**" with respect to Unforced Capacity shall mean the ability to determine the quantity or price of offers to supply Unforced Capacity from a Mitigated Capacity Zone Installed Capacity Supplier submitted into an ICAP Spot Market Auction; but excluding ISP UCAP MW or UCAP from an RMR Generator.

For purposes of Section 23.4.5.7 "**CRIS MW**" shall mean the MW of Capacity for which CRIS was assigned to a Generator or UDR project pursuant to ISO OATT Sections 25, 30, or 32 (OATT Attachments S, X, or Z).

"**Developer**" shall have the meaning specified in the ISO's Open Access Transmission Tariff.

"**Electric Facility**" shall mean a Generator or an electric transmission facility.

For purposes of Section 23.4.5 of this Attachment H, "**Entity**" shall mean a corporation, partnership, limited liability corporation or partnership, firm, joint venture, association, joint-stock company, trust, unincorporated organization or other form of legal or juridical organization or entity.

"**Examined Facility**" shall mean (I) each proposed new Generator and proposed new UDR project, and each existing Generator that has ERIS only and no CRIS, that is a member of the Class Year Study, Additional SDU Study or Expedited Deliverability Study that requested CRIS, or that requested an evaluation of the transfer of CRIS rights from another location in the Class Year Facilities Study commencing in the calendar year in which the Class Year Facility Study determination is being made (the Capability Periods of expected entry as further described below in this Section, the "Mitigation Study Period"), and (II) each (i) existing Generator that did not have CRIS rights, and (ii) proposed new Generator and proposed new UDR project, provided such Generator under Subsection (i) or (ii) is an expected recipient of transferred CRIS rights at the same location regarding which the ISO has been notified by the transferor or the transferee of a transfer pursuant to OATT Attachment S Section 25.9.4 that will be effective on a date within the Mitigation Study Period ("Expected CRIS Transferee"). In the case of Co-located Storage Resources, the Intermittent Power Resource and the co-located Energy Storage Resource will each be a separate Examined Facility for purposes of the Buyer Side Mitigation Measures enumerated in Section 23.4.5.7 *et al*. of the Services Tariff. The term "Examined Facilities" does not include any facility exempt from an Offer Floor pursuant to the provisions of Section 23.4.5.7.7.

Exceptional Circumstances: shall mean one or more unavoidable circumstances, as determined by the ISO, that individually or collectively render as unavailable the data necessary for the ISO to perform an audit and review of a Market Party, pursuant to Section 23.4.5.6.2 of this Services Tariff. Exceptional Circumstances may include, but are not limited to: the inaccessibility of the physical facility; the inaccessibility of necessary documentation or other data; and the unavailability of information regarding the regulatory obligations with which the Market Party will be required to comply in order to return its Generator to service which regulatory obligations are not yet known but which will be made known by the applicable regulatory authority under existing laws and regulations provided that none of the above described circumstances are the result of delay or inaction by the Market Party. The magnitude of the repair cost, alone, shall not be an Exceptional Circumstance.

"**Exempt Renewable Technology**" shall mean, in all Mitigated Capacity Zones, an Intermittent Power Resource solely powered by wind or solar energy.

"**Expedited Deliverability Study**" shall mean a deliverability study that an eligible Developer may elect to pursue as that term is defined in OATT Section 25 (OATT Attachment S) that may determine the extent to which an existing or proposed facility satisfies the NYISO Deliverability Interconnection Standard at its requested CRIS level without the need for System Deliverability Upgrades. The schedule and scope of the study is defined in Sections 25.5.9.2.1 and 25.7.1.2 of this Attachment S.

"**Final Decision Round**" shall have the meaning specified in Section 25 (Attachment S) of the ISO's Open Access Transmission Tariff.

For purposes of Section 23.4.5 of this Attachment H, "**Going-Forward Costs**" shall mean: either (a) the costs, including but not limited to mandatory capital expenditures necessary to comply with federal or state environmental, safety or reliability requirements that must be met in order to supply Installed Capacity, net of anticipated energy and ancillary services revenues, as determined by the ISO as specified in Section 23.4.5.3, for each of the following instances, as applicable, of supplying Installed Capacity that could be avoided if an Installed Capacity Supplier otherwise capable of supplying Installed Capacity were either (1) to cease supplying Installed Capacity and Energy for a period of one year or more while retaining the ability to re-enter such markets, or (2) to retire permanently from supplying Installed Capacity and Energy; or (b) the opportunity costs of foregone sales outside of a Mitigated Capacity Zone, net of costs that would have been incurred as a result of the foregone sale if it had taken place.

For purposes of Section 23.4.5 of this Attachment H, "**Indicative Mitigation Net CONE**" shall mean the capacity price calculated by the NYISO for informational purposes only if there is not an effective ICAP Demand Curve and the Commission (i) has accepted an ICAP Demand Curve for the Mitigated Capacity Zone that will become effective when the Mitigated Capacity Zone is first effective, in which case, the Indicative Mitigation Net CONE shall be the capacity price on such ICAP Demand Curve for the Mitigated Capacity Zone corresponding to the average amount of excess capacity above the Indicative NCZ Locational Minimum Installed Capacity Requirement, as applicable, expressed as a percentage of that requirement that formed the basis for the ICAP Demand Curve accepted by the Commission; or, (ii) has not accepted an ICAP Demand Curve for the Mitigated Capacity Zone, but the ISO has filed an ICAP Demand Curve for the Mitigated Capacity Zone pursuant to Services Tariff Section 5.14.1.2.2.4.11, in which case the Indicative Mitigation Net CONE shall be the capacity price on such ICAP Demand Curve corresponding to the average amount of excess capacity above the Indicative NCZ Locational Minimum Installed Capacity Requirement, expressed as a percentage of that requirement, that formed the basis for such ICAP Demand Curve.

"**Incremental Regulatory Retirement**" shall mean, for purposes of Section 23.4.5 of this Attachment H, the loss of ICAP Supply MW identified by the ISO in accordance with Section 23.4.5.7.13.5.3 in Class Year 2019, and subsequent Class Year Studies, Additional SDU Studies, and Expedited Deliverability Studies that start after July 1, 2020 and will be used in the ISO's calculation of the Renewable Exemption Limit.

"**Initial Decision Period**" shall have the meaning specified in Section 25 (Attachment S) of the ISO's Open Access Transmission Tariff.

"**Interconnection Customer**" shall have the meaning specified in Section 32 (Attachment Z) of the ISO's Open Access Transmission Tariff.

"**Interconnection Facilities Study Agreement**" shall have the meaning specified in Section 30 (Attachment X) of the ISO's Open Access Transmission Tariff.

"**Market Monitoring Unit**" shall have the same meaning in these Mitigation Measures as it has in Attachment O.

"**Market Party**" shall mean any person or entity that is, or for purposes of the determinations to be made pursuant to Section 23.4.5.7 of this Attachment H proposes or plans a Project that would be, a buyer and /or a seller in; or that makes bids or offers to buy or sell in; or that schedules or seeks to schedule Transactions with the ISO in or affecting any of the ISO Administered Markets including through the submission of bids or offers into any External Control Area, or any combination of the foregoing.

"**Minimum Renewable Exemption Limit**" shall mean, for purposes of Section 23.4.5 of this Attachment H, the UCAP value calculated by the ISO in Class Year 2019 and subsequent Class Year Studies in accordance with Section 23.4.5.7.13.5.1 to be used in the ISO's calculation of the Renewable Exemption Limit.

"**Mitigation Study Period**" shall mean the duration of time extending six consecutive Capability Periods and beginning with the Starting Capability Period associated with a Class Year Study, Additional SDU Study, and/or Expedited Deliverability Study.

For purposes of Section 23.4.5 of this Attachment H, "**Mitigated UCAP**" shall mean one or more megawatts of Unforced Capacity that are subject to Control by a Market Party that has been identified by the ISO as a Pivotal Supplier.

For purposes of Section 23.4.5 of this Attachment H, “**Mitigation Net CONE**” shall mean the capacity price on the currently effective ICAP Demand Curve for the Mitigated Capacity Zone corresponding to the average amount of excess capacity above the Mitigated Capacity Zone Installed Capacity requirement, expressed as a percentage of that requirement, that formed the basis for the ICAP Demand Curve approved by the Commission.

“**NCZ Examined Project**” shall mean any Generator or UDR project that is not exempt pursuant to 23.4.5.7.8 and either (i) is in a Class Year on the date the Commission accepts the first ICAP Demand Curve to apply to a Mitigated Capacity Zone or (ii) meets the criteria specified in 23.4.5.7.3(II). An NCZ Examined Project may be at any phase of development or in operation or an Installed Capacity Supplier.

For purposes of Section 23.4.5 of this Attachment H, “**Net CONE**” shall mean the localized levelized embedded costs of a peaking unit in a Mitigated Capacity Zone, net of the likely projected annual Energy and Ancillary Services revenues of such unit, as determined in connection with establishing the Demand Curve for a Mitigated Capacity Zone pursuant to Section 5.14.1.2 of the Services Tariff, or as escalated as specified in Section 23.4.5.7 of Attachment H.

“**New Capacity**” shall mean a new Generator, a substantial addition to the capacity of an existing Generator, or the reactivation of all or a portion of a Generator that has been out of service for five years or more that commences commercial service after the effective date of this definition.

For purposes of Section 23.4.5 of this Attachment H, “**Offer Floor**” for a Mitigated Capacity Zone Installed Capacity Supplier that is not a Special Case Resource shall mean the lesser of (i) a numerical value equal to 75% of the Mitigation Net CONE translated into a seasonally adjusted monthly UCAP value (“Mitigation Net CONE Offer Floor”), or (ii) the numerical value that is the first year value of the Unit Net CONE determined as specified in Section 23.4.5.7, translated into a seasonally adjusted monthly UCAP value using an appropriate class outage rate, (“Unit Net CONE Offer Floor”). The Offer Floor for a Mitigated Capacity Zone Installed Capacity Supplier that is a Special Case Resource shall mean a numerical value determined as specified in Section 23.4.5.7.5. The Offer Floor for Additional CRIS MW shall mean a numerical value determined as specified in Section 23.4.5.7.6.

For the purposes of Section 23.4.5 of this Attachment H, **“Non-Qualifying Entry Sponsors”** shall mean a Transmission Owner, Public Power Entity, or any other entity with a Transmission District in the NYCA, or an agency or instrumentality of New York State or a political subdivision thereof.

“**Owner**” shall have the meaning specified in Section 31.1.1 of the ISO’s Open Access Transmission Tariff.

For purposes of Section 23.4.5 of this Attachment H, “**Pivotal Supplier**” shall mean (i) for the New York City Locality, a Market Party that, together with any of its Affiliated Entities, (a) Controls 500 MW or more of Unforced Capacity, and (b) Controls Unforced Capacity some portion of which is necessary to meet the New York City Locality Locational Minimum Installed

Capacity Requirement in an ICAP Spot Market Auction; (ii) for the G-J Locality, a Market Party that, together with any of its Affiliated Entities, (a) Controls 650 MW or more of Unforced Capacity; and (b) Controls Unforced Capacity some portion of which is necessary to meet the G-J Locality Locational Minimum Installed Capacity Requirement in an ICAP Spot Market Auction; and (iii) for each Mitigated Capacity Zone except the New York City Locality and the G-J Locality, if any, a Market Party that Controls at least the quantity of MW of Unforced Capacity specified for the Mitigated Capacity Zone and accepted by the Commission. Unforced Capacity that are MW of an External Sale of Capacity shall not be included in the foregoing calculations

"**Project Cost Allocation**" shall have the meaning specified in Section 25 (Attachment S) of the ISO's Open Access Transmission Tariff.

"**Project**" shall have the meaning specified in Section 30.1 of the ISO's Open Access Transmission Tariff.

For purposes of Section 23.4.5 of this Attachment H, "**Responsible Market Party**" shall mean the Market Party that is authorized, in accordance with ISO Procedures, to submit offers in an ICAP Spot Market Auction to sell Unforced Capacity from a specified Installed Capacity Supplier.

"**Qualified Renewable Exemption Applicant**" shall mean a Renewable Exemption Applicant that the ISO has determined met the requirements to receive a Renewable Exemption as specified in Section 23.4.5.7.13.1.1 and may be awarded a Renewable Exemption as part of Class Year 2019, and any subsequent Class Year Studies, Additional SDU Studies or Expedited Deliverability Studies subject to the Renewable Exemption Limit calculated and implemented by the ISO as described in Sections 23.4.5.7.13.5 and 23.4.5.7.13.6 of this Attachment H to the Services Tariff.

"**Renewable Exemption Applicant**" shall mean, for purposes of Section 23.4.5 of this Attachment H, a Developer of an Examined Facility in Class Year 2019, and any subsequent Class Year Studies, Additional SDU Studies or Expedited Deliverability Studies that has requested that the ISO evaluate the Examined Facility for a Renewable Exemption. A UDR project may not be a Renewable Exemption Applicant, however, the Intermittent Power Resource that participates in a CSR may be a Renewable Exemption Applicant and Qualified Renewable Exemption Applicant.

"Renewable Exemption Bank" shall mean the amount of UCAP MW calculated separately for each Mitigated Capacity Zone by the ISO to remain available as described in Section 23.4.5.7.13.5.5 from the most recently completed Class Year Study, Additional SDU Study or Expedited Deliverability Study after deducting the UCAP equivalent MW of awarded Renewable Exemptions in that most recent study from the Renewable Exemption Limit.

"Renewable Exemption Limit" shall mean the maximum amount of UCAP MW calculated by the ISO in accordance with Section 23.4.5.7.13.5.5 in Class Year 2019 and any subsequent Class Year Studies, Additional SDU Studies, and Expedited Deliverability Studies that start after July

1, 2020 that is available for Qualified Renewable Exemption Applicants to receive Renewable Exemptions pursuant to section 23.4.5.7.13.

"**Revised Project Cost Allocation**" shall have the meaning specified in Section 25 (Attachment S) of the ISO's Open Access Transmission Tariff.

"Self Supply LSE" shall mean a Load Serving Entity in one or more Mitigated Capacity Zones that operates under a long-standing business model to meet more than fifty percent of its Load obligations through its own generation and that is (i) a municipally owned electric system that owns or controls distribution facilities and provides electric service, (ii) a cooperatively owned electric system that owns or controls distribution facilities and provides electric service,, (iii) a "Single Customer Entity," or (iv) a "Vertically Integrated Utility." A Self Supply LSE cannot be an entity that is a public authority or corporate municipal instrumentality, including a subsidiary thereof, created by the State of New York that owns or operates generation or transmission and that is authorized to produce, transmit or distribute electricity for the benefit of the public. For purposes of this definition only: "Vertically Integrated Utility" means a utility that owns generation, includes such generation in a non-bypassable charge in its regulated rates, earns a regulated return on its investment in such generation, and that as of the date of its request for a Self Supply Exemption, has not divested more than seventy-five percent of its generation assets owned on May 20, 1996; and "Single Customer Entity" means an LSE that serves at retail only customers that are under common control with such LSE, where such control means holding 51% or more of the voting securities or voting interests of the LSE and all its retail customers.

"Starting Capability Period" is the Summer Capability Period that will commence three years from the start of the year of the Class Year Study and shall be the start of the Mitigation Study Period for any Examined Facility in a Class Year Study, as well as any Additional SDU Studies and Expedited Deliverability Studies and that are completed while the Class Year Study is ongoing. If no Class Year Study is ongoing when an Expedited Deliverability Study or Additional SDU Study arrives at the Decision Period, the Starting Capability Period used for the purposes of Section 23.4.5 of this Attachment H shall be the Starting Capability Period that applied to the most recently completed Class Year Study.

"**Subsequent Decision Period**" shall have the meaning specified in Section 25 (Attachment S) of the ISO's Open Access Transmission Tariff.

For purposes of Section 23.4.5 of this Attachment H, "**Surplus Capacity**" shall mean the amount of Installed Capacity, in MW, available in a Mitigated Capacity Zone in excess of the Locational Minimum Installed Capacity Requirement for such Mitigated Capacity Zone.

"**Total Evaluated CRIS MW**" shall mean the Additional CRIS MW requested plus either (i) if the Installed Capacity Supplier previously received an exemption under Sections 23.4.5.7.2(b), 23.4.5.7.6(b), 23.4.5.7.7 or 23.4.5.7.8, all prior Additional CRIS MW since the facility was last exempted under Sections 23.4.5.7.2(b), 23.4.5.7.6(b), or 23.4.5.7.8, or (ii) for all other Installed Capacity Suppliers, all MW of Capacity for which an Examined Facility obtained CRIS pursuant to the provisions in ISO OATT Sections 25, 30, or 32 (OATT Attachments S, X, or Z).

For purposes of Section 23.4.5 of this Attachment H, “**UCAP Offer Reference Level**” shall mean a dollar value equal to the projected clearing price for each ICAP Spot Market Auction determined by the ISO on the basis of the applicable ICAP Demand Curve and the total quantity of Unforced Capacity from all Installed Capacity Suppliers in a Mitigated Capacity Zone for the period covered by the applicable ICAP Spot Market Auction.

For purposes of Section 23.4.5 of this Attachment H, “**Unit Net CONE**” shall mean localized levelized embedded costs of a specified Installed Capacity Supplier, including interconnection costs, and for an Installed Capacity Supplier located outside a Mitigated Capacity Zone including embedded costs of transmission service, in either case net of likely projected annual Energy and Ancillary Services revenues, and revenues associated with other energy products (such as energy services and renewable energy credits, as determined by the ISO, translated into a seasonally adjusted monthly UCAP value using an appropriate class outage rate. The Unit Net CONE of an Installed Capacity Supplier that has functions beyond the generation or transmission of power shall include only the embedded costs allocated to the production and transmission of power, and shall not net the revenues from functions other than the generation or transmission of power.

“Unforced Capacity Reserve Margin” or “URM” shall mean the megawatt value calculated by the ISO when converting the (a) the Installed capacity Reserve Margin (IRM) for the NYCA or (b) the Locational Minimum Installed Capacity Requirement (LCR) for a given Locality within the NYCA into UCAP terms using ICAP to UCAP conversion factors consistent with the corresponding resource adequacy study.

23.2.2 Conduct Subject to Mitigation

Mitigation Measures may be applied: (i) to the bidding, scheduling or operation of an “Electric Facility”; or (ii) as specified in Section 23.2.4.2.

23.2.3 Conditions for the Imposition of Mitigation Measures

23.2.3.1 To achieve the foregoing purpose and objectives, Mitigation Measures should only be imposed to remedy conduct that would substantially distort or impair the competitiveness of any of the ISO Administered Markets. Accordingly, the ISO shall seek to impose Mitigation Measures only to remedy conduct that:

23.2.3.1.1 is significantly inconsistent with competitive conduct; and

23.2.3.1.2 would result in a material change in one or more prices in an ISO Administered Market or production cost guarantee payments (“guarantee payments”) to a Market Party.

23.2.3.2 In general, the ISO shall consider a Market Party's or its Affiliates’ conduct to be inconsistent with competitive conduct if the conduct would not be in the economic interest of the Market Party or its Affiliates in the absence of market power. The categories of conduct that are inconsistent with competitive conduct include, but may not be limited to, the three categories of conduct specified in Section 23.2.4 below.

23.2.4 Categories of Conduct that May Warrant Mitigation

23.2.4.1 The following categories of conduct, whether by a single firm or by multiple firms acting in concert, may cause a material effect on prices or guarantee payments in an ISO Administered Market if exercised from a position of market power. Accordingly, the ISO shall monitor the ISO Administered Markets for the following categories of conduct, and shall impose appropriate Mitigation Measures if such conduct is detected and the other applicable conditions for the imposition of Mitigation Measures are met:

23.2.4.1.1 Physical withholding of an Electric Facility, that is, not offering to sell or schedule the output of or services provided by an Electric Facility capable of serving an ISO Administered Market. Such withholding may include, but not be limited to, (i) falsely declaring that an Electric Facility has been forced out of service or otherwise become unavailable, (ii) refusing to offer Bids or schedules for an Electric Facility when such conduct would not be in the economic interest of the Market Party or its Affiliates in the absence of market power (includes refusing to offer Bids or schedules to withdraw Energy for a Generator that must withdraw Energy in order to be able to later inject Energy); (iii); making an unjustifiable change to one or more operating parameters of an Electric Facility that reduces a Resource's ability to provide Energy or Ancillary Services or (iv) operating a Generator in real-time at a lower output level than the Generator would have been expected to provide had the Generator followed the ISO's dispatch instructions, in a manner that is not attributable to the Generator's verifiable physical operating capabilities and that would not be in the economic interest of the Market Party or its Affiliates in the absence of market power.

For purposes of this Section and Section 23.4.3.2, the term "unjustifiable change" shall mean a change in an Electric Facility's operating parameters that is: (a) not attributable to an Electric Facility's verifiable physical operating capabilities, and (b) is not a rational competitive response to economic factors other than market power.

23.2.4.1.2 Economic withholding of an Electric Facility, that is, submitting Bids for an Electric Facility that are unjustifiably high so that (i) the Electric Facility is not or will not be dispatched or scheduled, or (ii) the Bids will set a market clearing price; or submitting Bids for a Withdrawal-Eligible Generator to withdraw Energy that are unjustifiably high, so that (i) the Electric Facility is or will be dispatched or scheduled to withdraw Energy, or (ii) the Bids will set a market clearing price.

23.2.4.1.3 Uneconomic production from an Electric Facility, that is, increasing the output of an Electric Facility to levels that would otherwise be uneconomic in order to cause, and obtain benefits from, a transmission constraint.

23.2.4.2 Mitigation Measures may also be imposed, subject to FERC's approval, to mitigate the market effects of a rule, standard, procedure or design feature of an ISO Administered Market that allows a Market Party or its Affiliate to manipulate market prices or otherwise impair the efficient operation of that market, pending the revision of such rule, standard, procedure or design feature to preclude such manipulation of prices or impairment of efficiency.

23.2.4.3 Taking advantage of opportunities to sell at a higher price or buy at a lower price in a market other than an ISO Administered Market shall not be deemed a form of withholding or otherwise inconsistent with competitive conduct.

23.2.4.4 The ISO and the Market Monitoring Unit shall monitor the ISO Administered Markets for other categories of conduct, whether by a single firm or by multiple firms acting in concert, that have material effects on prices or guarantee payments in an ISO Administered Market. The ISO shall: (i) seek to amend the foregoing list as may be appropriate, in accordance with the procedures and requirements for amending the Plan, to include any such conduct that would substantially distort or impair the competitiveness of any of the ISO Administered Markets; and (ii) seek such other authorization to mitigate the effects of such conduct from the FERC as may be appropriate. The responsibilities of the Market

Monitoring Unit that are addressed in this section of the Mitigation Measures are also addressed in Section 30.4.6.2.2 of Attachment O.

23.3 Criteria for Imposing Mitigation Measures

23.3.1 Identification of Conduct Inconsistent with Competition

Conduct that may potentially warrant the imposition of a mitigation measure includes the categories described in Section 23.2.4 above, which shall be detected through the use of indices and screens developed, adopted and made available as specified in Attachment O. The thresholds listed in Sections 23.3.1.1 to 23.3.1.3 below shall be used to identify substantial departures from competitive conduct indicative of an absence of workable competition.

23.3.1.1 Thresholds for Identifying Physical Withholding

23.3.1.1.1 The following initial thresholds will be employed by the ISO to identify physical withholding of a Generator or generation or a CSR Scheduling Limit by a Market Party and its Affiliates:

23.3.1.1.1.1 Except for conduct addressed in Section 23.3.1.1.1.2: Withholding that exceeds (i) 10 percent of a Generator's capability or 10 percent of a CSR Scheduling Limit, or (ii) 100 MW of a Generator's capability or 100 MW of a CSR Scheduling Limit, or (iii) 5 percent of the total capability of a Market Party and its Affiliates, or (iv) 200 MW of the total capability of a Market Party and its Affiliates.

For a Generator or a Market Party in a Constrained Area for intervals in which an interface or facility into the area in which the Generator or generation is located has a Shadow Price greater than $0.04/MWh, indicating an active constraint, withholding that exceeds (i) 10 percent of a Generator's capability or 10 percent of a CSR Scheduling Limit, or (ii) 50 MW of a Generator's capability or 50 MW of a CSR Scheduling Limit, or (iii) 5 percent of the total capability of a

Market Party and its Affiliates, or (iv) 100 MW of the total capability of a Market Party and its Affiliates.

23.3.1.1.1.2 Operating a Generator or generation in real-time at a lower output level than would have been expected had the Market Party's and its Affiliate's Generator or generation followed the ISO's dispatch instructions, resulting in a difference in output that exceeds (i) 15 minutes times a Generator's stated response rate per minute at the output level that would have been expected had the Generator followed the ISO's dispatch instructions, or (ii) 100 MW for a Generator, or (iii) 200 MW of the total capability of a Market Party and its Affiliates. For a Generator or a Market Party in a Constrained Area for intervals in which an interface or facility into the area in which the generation is located has a Shadow Price greater than $0.04/MWh, indicating an active constraint, operating a Generator or generation in real-time at a lower output level than would have been expected had the Market Party's and its Affiliate's Generator or generation followed the ISO's dispatch instructions, resulting in a difference in output that exceeds (i) 15 minutes times a Generator's stated response rate per minute at the output level that would have been expected had the Generator followed the ISO's dispatch instructions, or (ii) 50 MW of a Generator's capability, or (iii) 100 MW of the total capability of a Market Party and its Affiliates.

23.3.1.1.2 The amounts of generating capacity considered withheld for purposes of applying the thresholds in this Section 23.3.1.1 shall include unjustified deratings, and the portions of a Generator's output that is not Bid or subject to economic withholding. The amounts deemed withheld shall not include (i) generating output that is subject to a forced outage, subject to verification by the ISO as may be appropriate that an outage was forced, (ii) capacity that is out of service for maintenance in accordance with an ISO maintenance schedule, or (iii) generating capacity that is not Bid in the Real-Time Market, because and to the extent it would have to use unauthorized natural gas to operate, subject to verification by the ISO as may be appropriate that operation would require the use of unauthorized natural gas. See Section 23.3.1.4.6.2.1.1 below.

23.3.1.1.3 A transmission facility shall be deemed physically withheld if it is not operated in accordance with ISO instructions and such failure to conform to ISO instructions causes or contributes to transmission congestion. A transmission facility shall not be deemed withheld if it is subject to a forced outage or is out of service for maintenance in accordance with an ISO maintenance schedule.

23.3.1.2 Thresholds for Identifying Economic Withholding

23.3.1.2.1 The following thresholds shall be employed by the ISO to identify economic withholding that may warrant the mitigation of a Generator in an area that is not a Constrained Area, or in a Constrained Area during periods not subject to transmission constraints affecting the Constrained Area, and shall be determined with respect to a reference level determined as specified in Section 23.3.1.4:

23.3.1.2.1.1 Incremental Energy and Minimum Generation Bids: An increase exceeding 300 percent or $100 per MWh, whichever is lower; provided, however, that Incremental Energy or Minimum Generation Bids below $25 per MWh shall be deemed not to constitute economic withholding when evaluating Bids to produce Energy.

23.3.1.2.1.1.1 Threshold for Bids to withdraw Incremental Energy: an increase exceeding 300 percent or $100 per MWh, whichever is lower. However, the threshold for Bids to withdraw Incremental Energy that have an associated reference level that is between -$25 and $25 per MWh (inclusive) is, instead, $75 per MWh.

23.3.1.2.1.1.2 Additional Thresholds used to assess Bids for Generators that the ISO evaluates as a price spread for purposes of scheduling and dispatch.

The following hourly and daily thresholds will be employed to evaluate the spread between the minimum and maximum dollar values included in a Withdrawal-Eligible Generator's multi-step incremental Energy Bid. The time periods over which the comparisons are performed are specified below.

(a) Hourly Threshold (applies to both the Day-Ahead and Real-Time Markets)—the Incremental Energy Bid spread is compared to the Incremental Energy reference level spread for the same market hour. The Bid spread is determined by subtracting the least Incremental Energy Bid price from the greatest Incremental Energy Bid price. This value is compared to the reference level spread, which is determined by subtracting the Incremental Energy reference level price that corresponds to the least Incremental Energy Bid price from the Incremental Energy reference level price that corresponds to the greatest Incremental Energy Bid price. A Bid spread that exceeds the reference level spread by more than 300 percent or by more than $100 per MWh, whichever is lower, exceeds the conduct threshold.

(b) Daily Threshold (only applies to the Day-Ahead Market)—the Incremental Energy Bid spread across the Day-Ahead market day is compared to the Incremental Energy reference level spread. The Bid spread is determined by subtracting the least Incremental Energy Bid price submitted for any hour of the Day-Ahead market day (“Hour X”) from the greatest Incremental Energy Bid price submitted for any hour of the same market-day (“Hour Y”). Hour X and Hour Y can be the same market hour. This value is compared to the reference level spread, which is determined by subtracting the Incremental Energy reference level price Bid that corresponds to the least Incremental Energy Bid price in Hour X from the Incremental Energy reference level price that corresponds to the greatest Incremental Energy Bid price in Hour Y. A Bid spread that exceeds the reference level spread by more than 300 percent or by more than $100 per MWh, whichever is lower, exceeds the conduct threshold.

23.3.1.2.1.2 Operating Reserves and Regulation Service Bids:

23.3.1.2.1.2.1 Operating Reserves and Regulation Capacity Bids: A 300 percent increase or an increase of $50 per MW, whichever is lower; provided, however, that such Bids below $5 per MW shall be deemed not to constitute economic withholding.

23.3.1.2.1.2.2 Regulation Movement Bids: A 300 percent increase.

23.3.1.2.1.3 Start-Up Bids: A 200 percent increase.

23.3.1.2.1.4 Time-based Bid parameters: An increase of 3 hours, or an increase of 6 hours in total for multiple time-based Bid parameters. Time-based Bid parameters include, but are not limited to, start-up times, minimum run times, minimum down times, and temporal minimum and maximum parameters related to the withdrawal and injection of Energy by Withdrawal-Eligible Generators.

23.3.1.2.1.5 Bid parameters expressed in units other than time or dollars, including the MW component of a Minimum Generation Bid (also referred to as the "minimum operating level"): A 100 percent increase for parameters that are minimum values, or a 50 percent decrease for parameters that are maximum values (including but not limited to ramp rates, maximum stops, and operating parameters related to the withdrawal and injection of Energy by Withdrawal-Eligible Generators).

23.3.1.2.2 The following thresholds shall be employed by the ISO to identify economic withholding that may warrant the mitigation of a Generator in an area that is a Constrained Area, and shall be determined with respect to a reference level determined as specified in Section 23.3.1.4:

23.3.1.2.2.1 For Energy and Minimum Generation Bids for the Real-Time Market: for intervals in which an interface or facility into the area in which a Generator is located has a Shadow Price greater than \$0.04/MWh, indicating an active constraint, the lower of the thresholds specified for areas that are not Constrained Areas or a threshold determined in accordance with the following formula:

$$Threshold = \frac{2\% * Average\ Price * 8760}{Constrained\ Hours}$$

where:

Average Price = the average price in the Real-Time Market in the Constrained Area over the past 12 months, adjusted for fuel price changes, and adjusted for Out-of-Merit Generation dispatch as feasible and appropriate; and

Constrained Hours = the total number of minutes over the prior 12 months, converted to hours (retaining fractions of hours), in which the real-time Shadow Price has been greater than $0.04/MWh, indicating an active constraint, on any interface or facility leading into the Constrained Area in which the Generator is located. For the In-City area, "Constrained Hours" shall also include the number of minutes that a Storm Watch is in effect. Determination of the number of Constrained Hours shall be subject to adjustment by the ISO to account for significant changes in system conditions.

23.3.1.2.2.2 For so long as the In-City area is a Constrained Area, the thresholds specified in subsection 23.3.1.2.2.1 shall also apply: (a) in intervals in which the transmission capacity serving the In-City area is subject to Storm Watch limitations; (b) to an In-City Generator that is operating as Out-of-Merit Generation; and (c) to a Generator dispatched as a result of a Supplemental Resource Evaluation.

23.3.1.2.2.3 For Energy and Minimum Generation Bids for the Day-Ahead Market: for all Constrained Hours for the Generator being Bid, a threshold determined in accordance with the formula specified in subsection 23.3.1.2.2.1 above, but where Average Price shall mean the average price in the Day-Ahead Market in the Constrained Area over the past twelve months, adjusted for fuel price changes, and where Constrained Hours shall mean the total number of hours over the prior 12 months in which the Shadow Price in the Day-Ahead Market has been greater than $0.04/MWh, indicating an active constraint, on any interface or facility leading into the Constrained Area in which the Generator is located. Determination of the number of Constrained Hours shall be subject to adjustment by the ISO to account for significant changes in system conditions.

23.3.1.2.2.4 For Start-Up Bids; a 50% increase.

23.3.1.2.2.5 The thresholds listed in Sections 23.3.1.2.1.2 and 23.3.1.2.1.4 through 23.3.1.2.1.5.

23.3.1.2.2.6 For intervals in which an interface or facility into the area in which a Generator is located has a Shadow Price greater than $0.04/MWh, indicating an active constraint in the Day-Ahead Market or in the Real-Time Market, the additional thresholds used to assess Bids for Generators that the ISO evaluates as a price spread for purposes of scheduling and dispatch are set forth below. The evaluation method is described in Section 23.3.1.2.1.1.2 of these Mitigation Measures.

(a) Hourly Threshold (applies to both the Day-Ahead and Real-Time Markets)—the Incremental Energy Bid spread is compared to the Incremental Energy reference level spread for the same market hour. The Bid spread is determined by subtracting the least Incremental Energy Bid price from the greatest Incremental Energy Bid price. This value is compared to the reference level spread, which is determined by subtracting the Incremental Energy reference level price that corresponds to the least Incremental Energy Bid price from the Incremental Energy reference level price that corresponds to the greatest Incremental Energy Bid price. A Bid spread that exceeds the reference level spread by more than the lower of the threshold specified for areas that are not Constrained Areas, or a threshold determined in accordance with the formulae set forth in Section 23.3.1.2.2.1 (real-time) or Section 23.3.1.2.2.3 (Day-Ahead) of these Mitigation Measures, exceeds the conduct threshold.

(b) Daily Threshold (only applies to the Day-Ahead Market)—the Incremental Energy Bid spread across the Day-Ahead market day is compared to the Incremental Energy reference level spread. The Bid spread is determined by subtracting the least Incremental Energy Bid price submitted for any hour of the Day-Ahead market day ("Hour X") from the greatest Incremental Energy Bid price submitted for any hour of the same market-day ("Hour Y"). Hour X and Hour Y can be the same market hour. This value is compared to the reference level spread, which is determined by subtracting the Incremental Energy reference level price Bid that corresponds to the least Incremental Energy Bid price in Hour X from the Incremental Energy reference level price that corresponds to the greatest Incremental Energy Bid price in Hour Y. A Bid spread that exceeds the reference level spread by more than the lower of the threshold specified for areas that are not Constrained Areas, or a threshold determined in accordance with the formula set forth in Section 23.3.1.2.2.3 (Day-Ahead) of these Mitigation Measures, exceeds the conduct threshold.

23.3.1.2.3 The following thresholds shall be employed by the ISO to identify economic withholding that requires the mitigation of a Generator that is committed outside the ISO's economic evaluation process to protect NYCA or local area reliability in an area that is not a designated Constrained Area. Whether the thresholds specified in Sections 23.3.1.2.3.3(i) through 23.3.1.2.3.3(vi) below have been exceeded shall be determined with respect to a reference level determined as specified in Section 23.3.1.4 of these Mitigation Measures.

If provisions 23.3.1.2.3.1 and 23.3.1.2.3.2 below are met for a Generator in the New York Control Area that is not located in a designated Constrained Area, the ISO shall substitute a reference level for each Bid, or component of a Bid, for which the applicable threshold specified in provisions 23.3.1.2.3.3(i) through 23.3.1.2.3.3(vi) below is exceeded. Where mitigation is determined to be appropriate, the mitigated results will be used in all aspects of the NYISO's settlement process.

23.3.1.2.3.1 The Generator was committed outside the ISO's economic merit order selection process to protect or maintain New York Control Area or local system reliability as a Day-Ahead Reliability Unit ("DARU") or via a Supplemental Resource Evaluation ("SRE"), or was committed as a DARU or via SRE and was also dispatched Out-of-Merit above its minimum generation level to protect or maintain New York Control Area or local system reliability; and

23.3.1.2.3.2 One of the following three (i) – (iii) conditions in this Section 23.3.1.2.3.2 must be satisfied in order for mitigation to be applied:

i the Market Party (including its Affiliates) that owns or offers the Generator is the only Market Party that could effectively solve the reliability need for which the Generator was committed or dispatched, or

ii when evaluating an SRE that was issued to address a reliability need that multiple Market Parties' Generators are capable of solving, the NYISO only received Bids from one Market Party (including its Affiliates), or iii when evaluating a DARU, if the Market Party was notified of the need for the reliability commitment of its Generator prior to the close of the Day-Ahead Market.

23.3.1.2.3.3 The Bids or Bid components submitted for the Generator that were accepted outside the economic evaluation process to protect or maintain New York Control Area or local system reliability:

i exceeded the Generator's Minimum Generation Bid reference level by the greater of 10% or $10/MWh, or

ii. exceeded the Generator's Incremental Energy Bid reference level by the greater of 10% or $10/MWh, or

iii. exceeded the Generator's Start-Up Bid reference level by 10%, or

iv. exceeded the Generator's minimum run time, start-up time, and minimum down time reference levels by more than one hour in aggregate, or

v. exceeded the Generator's minimum generation MW reference level by more than 10%, or

vi. decreased the Generator's maximum number of stops per day below the Generator's reference level by more than one stop per day, or to one stop per day.

23.3.1.2.4 For In-City Generators committed in the Day-Ahead Market for local reliability, additional Mitigation Measures are specified in Section 23.5.2.1.

23.3.1.3 Thresholds for Identifying Uneconomic Production and Uneconomic Withdrawal of Energy

23.3.1.3.1 The following thresholds will be employed by the ISO to identify uneconomic production that may warrant the imposition of a mitigation measure:

23.3.1.3.1.1 Energy scheduled at an LBMP that is less than 20 percent of the applicable reference level and causes or contributes to transmission congestion; or

23.3.1.3.1.2 Real-time output from a Generator or generation resulting in real-time operation at a higher output level than would have been expected had the Market Party's and the Affiliate's Generator or generation followed the ISO's dispatch instructions, if such failure to follow ISO dispatch instructions in real-time causes or contributes to transmission congestion, and it results in an output difference that exceeds (i) 15 minutes times a Generator's stated response rate per minute at the output level that would have been expected had the Generator followed the ISO's dispatch instructions, or (ii) 100 MW for a Generator, or (iii) 200 MW of the total capability of a Market Party and its Affiliates.

23.3.1.3.2 The following thresholds will be employed by the ISO to identify uneconomic withdrawals of Energy by Withdrawal-Eligible Generators that may warrant the imposition of a mitigation measure:

23.3.1.3.2.1 Energy withdrawn at an LBMP that is at least 300 percent or $75/MWh, whichever is greater, more than the Withdrawal-Eligible Generator's applicable reference level and that causes or contributes to transmission congestion; provided, however, that schedules to withdraw Energy that are determined by the ISO based on the economics of an offer to withdraw Energy, including the Incremental Energy Bid spread of a Withdrawal-Eligible Generator, shall not be considered uneconomic withdrawals under this Section 23.3.1.3.2.1; or

23.3.1.3.2.2 Real-time withdrawals by a Withdrawal-Eligible Generator resulting in different real-time operation than would have been expected had the Market

Party's and the Affiliate's Generator or generation followed the ISO's dispatch instructions, if such failure to follow ISO dispatch instructions in real-time causes or contributes to transmission congestion, and it results in an output difference that exceeds (i) 15 minutes times a Generator's stated response rate per minute at the output level that would have been expected had the Generator followed the ISO's dispatch instructions, or (ii) 100 MW for a Generator, or (iii) 200 MW of the total capability of a Market Party and its Affiliates.

23.3.1.4 Reference Levels

23.3.1.4.1 Except as provided in Sections 23.3.1.4.3 – 23.3.1.4.6 below, a reference level for each component of a Generator's Bid to produce Energy shall be calculated on the basis of the following methods, listed in the order of preference subject to the existence of sufficient data.

A reference level for each component of a Withdrawal-Eligible Generator's Bid to produce or withdraw Energy shall be calculated consistent with Sections 23.3.1.4.1.3 or 23.3.1.4.2 below, subject to the existence of sufficient data.

23.3.1.4.1.1 The lower of the mean or the median of a Generator's accepted Bids or Bid components, in hour beginning 6 to hour beginning 21 but excluding weekend and designated holiday hours, in competitive periods over the most recent 90 day period for which the necessary input data are available to the ISO's reference level calculation systems, adjusted for changes in fuel prices consistent with Section 23.3.1.4.6, below. To maintain appropriate reference levels (i) the ISO shall exclude all Incremental Energy and Minimum Generation Bids below $15/MWh from its development of Bid-based reference levels, (ii) the ISO shall exclude Minimum Generation Bids submitted for a Generator that was committed on the day prior to the Dispatch Day for the hours during the Dispatch Day that the Generator needs to operate in order to complete the minimum run time specified in the Bid it submitted for the hour in which it was committed, and (iii) the ISO may exclude other Bids that would cause a reference level to deviate substantially from a Generator's marginal cost when developing Bid-based reference levels;

23.3.1.4.1.2 Calculate incremental energy and minimum generation reference levels for a Generator using the mean of the LBMP at the Generator's location during the lowest-priced 50 percent of the hours that the Generator was dispatched over the most recent 90 day period for which the necessary LBMP data are available to the ISO's reference level calculation systems, adjusted for changes in fuel prices consistent with Section 23.3.1.4.6, below. To maintain appropriate reference levels (i) the ISO shall exclude all LBMPs below $15/MWh from its development of LBMP-based reference levels, (ii) the ISO shall exclude LBMPs during hours when a Generator was scheduled as a Day-Ahead Reliability Unit or via a Supplemental Resource Evaluation or was Out-of-Merit Generation, from its development of that Generator's LBMP-based reference levels, (iii) for a Generator that was committed on the day prior to the Dispatch Day, the ISO shall exclude LBMPs for the hours during the Dispatch Day that the Generator needs to operate in order to complete the minimum run time specified in the Bid it submitted for the hour in which the Generator was committed from the ISO's development of that Generator's LBMP-based reference levels, and (iv) the ISO may exclude LBMPs that would cause a reference level to deviate substantially below a Generator's marginal cost when developing LBMP-based reference levels; or

23.3.1.4.1.3 A level determined in consultation with the Market Party submitting the Bid or Bids at issue, provided such consultation has occurred prior to the occurrence of the conduct being examined by the ISO, and provided the Market Party has provided data on a Generator's operating costs in accordance with specifications provided by the ISO.

The reference level for a Generator's Energy and Ancillary Service Bids are intended to reflect the Generator's marginal costs. The ISO's determination of a Generator's Energy marginal costs shall include an assessment of the Generator's incremental operating costs in accordance with the following formula:

$$\begin{aligned}(heat\ rate * fuel\ costs) + &\ (emissions\ rate * emissions\ allowance\ price)\\ &+ (other\ variable\ operating\ and\ maintenance\ costs)\\ &+ opportunity\ costs\end{aligned}$$

Opportunity cost is the cost, in dollars, representing (a) the total net revenue in the future time periods that is expected to be forgone by being dispatched by the ISO in the current time period, or (b) the total net cost in future time periods that is expected to be avoided by being dispatched by the ISO in the current time period. Opportunity costs are limited to costs that the ISO reasonably determines to be appropriate based on such data as may be furnished by the Market Party or otherwise available to the ISO. Reference levels shall also include such other factors or adjustments as the ISO shall reasonably determine to be appropriate based on such data as may be furnished by the Market Party or otherwise available to the ISO.

23.3.1.4.2 If sufficient data do not exist to calculate a reference level on the basis of either of the first two methods, or if the ISO determines that none of the three methods are applicable to a particular type of Bid component, or an attempt to determine a reference level in consultation with a Market Party has not been successful, or if the reference level produced does not reasonably approximate a Generator's marginal cost, the ISO shall determine a reference level on the basis of:

23.3.1.4.2.1 the ISO's estimate of the costs or physical parameters of an Electric Facility, taking into account available operating costs data, appropriate input from the Market Party, and the best information available to the ISO; or

23.3.1.4.2.2 an appropriate average of competitive bids of one or more similar Electric Facilities.

23.3.1.4.3 Notwithstanding the foregoing provisions, the reference level for Incremental Energy Bids for New Capacity, excluding Energy Storage Resources, for the three year and six month period following the New Capacity's first production of Energy while synchronously interconnected to the New York State Transmission System shall be the higher of (i) the amount determined in accordance with the provision of Section 23.3.1.4.1 or 23.3.1.4.2, or (ii) the average of the fuel price-adjusted peak LBMPs over the twelve months prior to the New Capacity's first production of Energy while synchronously interconnected to the New York State Transmission System of the New Capacity in the Load Zone in which the New Capacity is located during hours when Generators with operating characteristics similar to the New Capacity would be expected to run. For entities owning or otherwise controlling the output of capacity in the New York Control Area other than New Capacity, the provisions of this Section 23.3.1.4.3 shall apply only to net additions of capacity during the applicable three year and six month period.

23.3.1.4.4 Notwithstanding the foregoing provisions, a reference level for a Generator's start-up costs Bid shall be calculated on the basis of the following methods, listed in the order of preference subject to the existence of sufficient data:

23.3.1.4.4.1 If sufficient bidding histories under the applicable bidding rules for a given Generator's start-up costs Bids have been accumulated, the lower of the mean or the median of the Generator's accepted start-up costs Bids in competitive periods over the previous 90 days for similar down times, adjusted for changes in fuel prices consistent with Section 23.3.1.4.6 below. However, accepted Start-Up Bids that incorporate anticipated costs of operating on the day after the Dispatch Day in which the Generator is committed in order to permit the Generator to satisfy its minimum run time shall not be used to develop Bid-based start-up reference levels;

23.3.1.4.4.2 A level determined in consultation with the Market Party submitting the Bid or Bids at issue and intended to reflect the costs incurred for a Generator to achieve its specified minimum operating level from an offline state, provided such consultation has occurred prior to the occurrence of the conduct being examined by the ISO, and provided the Market Party has provided data on the Generator's operating costs in accordance with specifications provided by the ISO; or

23.3.1.4.4.3 Generators committed in the Day-Ahead Market or via Supplemental Resource Evaluation 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 (in MW) specified in the Generator's Bid for the commitment hour, for the hours necessary to complete the Generator's minimum run time. The NYISO will calculate a start-up reference level that incorporates the net costs the Generator is expected to incur on the day following the Dispatch Day as follows:

23.3.1.4.4.3.1 Calculation of a start-up reference level that includes expected net costs of operating on the day following the Dispatch Day

The NYISO will use the following calculation to develop a reference level that incorporates the costs that a Generator is expected to incur on the day following the Dispatch Day.

$$LateDayAdjusted_{g,i} = StrtUpRef_g + \max\left(0, MinGenRef_{g,i} * BidMinGen_{g,i} * \sum_{h=0}^{Z_{g,i}-1} SR_{g,h,i}\right)$$

Where:

$LateDayAdjusted_{g,i}$ = calculated start-up reference level for Generator g for hour i in \$ (reflects the applicable start-up reference level ($StrtUpRef_g$), plus the expected net cost of operating on the day following the Dispatch Day)

$StrtUpRef_g$ = the start-up reference level for Generator g in \$ that is in effect at the time the calculation is performed (does not include the expected net cost of operating on the day following the Dispatch Day)

$MinGenRef_{g,i}$ = the minimum generation cost reference level for Generator g for hour i in \$/MW that is in effect at the time the calculation is performed

$BidMinGen_{g,i}$ = Generator g's Day-Ahead minimum operating level for hour i, in MW

$Z_{g,i}$ = the number of hours the Generator must operate during the day following the Dispatch Day in order to complete its minimum run time if it starts in hour i

$SR_{g,h,i}$ = shortfall ratio for Generator g that is bidding to start in hour i which must run during hour h in order to complete its minimum run time, calculated in accordance with Section 23.3.3.4.4.3.2, below

23.3.1.4.4.3.2 Calculation of the shortfall ratio for use in Section 23.3.1.4.4.3.1, above

$SR_{g,h,i}$ = the shortfall ratio calculated for Generator g that is bidding to start in hour i, and that must run during hour h to complete its minimum run time.

In all cases in which Generator g's Day-Ahead minimum operating level deviates from the average of the previous seven days' Day-Ahead minimum operating levels for the same hour by less than 5 MW (*i.e.*, if $|AvgBidMinGen_{g,h,i} - BidMinGen_{g,i}| < 5MW$) or by less than 10% (*i.e.*, if both $BidMinGen_{g,i} < 1.1 * AvgBidMinGen_{g,h,i}$ and $BidMinGen_{g,i} > 0.9 * AvgBidMinGen_{g,h,i}$),

Where:

$AvgBidMinGen_{g,h,i}$ = The average minimum operating level submitted in the Day-Ahead Market for hour h on the seven days preceding the day containing hour i, in MW, excluding any days for which a minimum operating level was not submitted in the Day-Ahead Market for Generator g, for hour h; and

$BidMinGen_{g,i}$ = The minimum operating level submitted in the Day-Ahead Market for Generator g for hour i, in MW

and in all cases in which $AvgBidMinGen_{g,h,i}$ cannot be calculated because minimum operating levels were not submitted for Generator g in the Day-Ahead Market for hour h on any of the seven days preceding the day containing hour i, the $SR_{g,h,i}$ value will be calculated using the primary method. Otherwise, the $SR_{g,h,i}$ value will be calculated using the alternative method.

Primary Method of Calculating the Shortfall Ratio

$$SR_{g,h,i} = 1 - \frac{1}{7} * \sum_{d=1}^{7} \frac{LBMP_{g,h,i,d}}{MinGenRef_{g,h,i,d}}$$

Where:

$LBMP_{g,h,i,d}$ = Day ahead LBMP at the location of Generator g in hour h of the Day-Ahead Market for the Dispatch Day that precedes the day containing hour i by d days, and

$MinGenRef_{g,h,i,d}$ = minimum generation cost reference level for Generator g in hour h of the Day-Ahead Market for the Dispatch Day that precedes the day containing hour i by d days

Alternative Method of Calculating the Shortfall Ratio

$$SR_{g,h,i} = 1 - \frac{AvgLBMP_{g,h,i}}{\left(AvgRefRate_{g,h,i} * \frac{RefRate2_{g,i}}{RefRate1_{g,h,i}}\right)}$$

Where:

$AvgLBMP_{g,h,i}$ = The average of the Day-Ahead LBMPs at the location of Generator *g* for hour *h* on the seven days preceding the day containing hour *i*, in $/MWh, excluding any days for which a minimum operating level was not submitted in the Day-Ahead Market for Generator *g* for hour *h*

$AvgRefRate_{g,h,i}$ = The average of the minimum generation reference levels for Generator *g* in hour *h* on the seven days preceding the day containing hour *i*, in $/MWh, excluding any days for which a minimum operating level was not submitted in the Day-Ahead Market for Generator *g* for hour *h*

$RefRate1_{g,h,i}$ = The minimum generation cost reference level in $/MWh for Generator *g* for hour *i*, calculated using the most current reference data, and assuming that the minimum operating level submitted in the Day-Ahead Market for Generator *g* in hour *i* corresponds to the MWs reflected in the $AvgBidMinGen_{g,h,i}$

$RefRate2_{g,i}$ = The minimum generation cost reference level in $/MWh for Generator *g* for hour *i*, calculated using the most current reference data, and incorporating the minimum operating level submitted in the Day-Ahead Market for Generator *g* in hour *i* that corresponds to the MWs reflected in the $BidMinGen_{g,i}$

Notwithstanding the above, in all cases where the denominator of the equation for calculating $SR_{g,h,i}$ is not greater than zero, $SR_{g,h,i}$ shall be set to zero, under both the primary and alternative methods.

23.3.1.4.4.4 The methods specified in Section 23.3.1.4.2.

23.3.1.4.5 The ISO is not required to calculate real-time reference levels for the three Operating Reserve products (Spinning Reserve, 10-Minute Non-Synchronized Reserves and 30-Minute Reserves) because Generators that are capable of providing these products and that are submitting Bids into the Real-Time Market are automatically assigned a real-time Operating Reserves Availability Bid of zero for the amount of Operating Reserves they are capable of providing.

The ISO shall calculate real-time reference levels for Regulation Capacity in accordance with Sections 23.3.1.4.1.1, 23.3.1.4.1.3 or 23.3.1.4.2 of these Mitigation Measures. The ISO shall calculate real-time reference levels for Regulation Movement in accordance with Sections 23.3.1.4.1.3 or 23.3.1.4.2.1 of these Mitigation Measures and shall not calculate real-time Reference levels for Regulation Movement in accordance with Section 23.3.1.4.1.1.

The ISO shall calculate Day-Ahead reference levels for the three Operating Reserves products in accordance with Sections 23.3.1.4.1.1, 23.3.1.4.1.3 or 23.3.1.4.2 of these Mitigation Measures. The ISO shall calculate Day-Ahead reference levels for Regulation Capacity in accordance with Sections 23.3.1.4.1.1, 23.3.1.4.1.3 or 23.3.1.4.2 of these Mitigation Measures. The ISO shall calculate Day-Ahead reference levels for Regulation Movement in accordance with Sections 23.3.1.4.1.3 or 23.3.1.4.2.1 of these Mitigation Measures and shall not calculate Day-Ahead Reference levels for Regulation Movement in accordance with Section 23.3.1.4.1.1.

23.3.1.4.6 Reflecting Fuel Costs in Reference Levels. The ISO shall use the best fuel cost information available to it to adjust reference levels to reflect appropriate fuel costs.

23.3.1.4.6.1 ISO Reporting Obligation. If the ISO did not utilize the best fuel cost information available to it when it adjusted reference levels to reflect appropriate fuel costs, and the ISO's failure to utilize the best fuel cost information available to it affected market clearing prices or had an impact on guarantee payments that cannot be corrected, then the ISO shall report any market clearing price and uncorrected guarantee payment impacts to FERC staff and to its Market Participants. The ISO is not required to report, or to otherwise act, if no market impact is identified.

23.3.1.4.6.2 Market Parties shall monitor Generator reference levels and shall endeavor to timely (as that term is defined in Section 23.3.1.4.6.8 below) contact the ISO to request an adjustment to a Generator's reference level(s) when the Generator's fuel type or fuel price change.

23.3.1.4.6.2.1 Subject to the exceptions set forth in Section 23.3.1.4.6.2.1.2 below, the ISO shall not permit charges for unauthorized natural gas use to be included as a component in the development of a Generator's reference levels and Market Parties shall not be eligible to recover costs associated with unauthorized natural gas use.

23.3.1.4.6.2.1.1 What constitutes "unauthorized" natural gas use is specified in each natural gas pipeline's or local distribution company's ("LDC's") applicable tariff, rate schedule or customer contract. Unauthorized natural gas use may result from, but is not limited to, the following circumstances: (i) consumption of natural gas in violation of the terms of an Operational Flow Order ("OFO") issued by the relevant natural gas LDC or pipeline; (ii) violation of instructions issued by the relevant natural gas LDC or pipeline restricting consumption of natural gas or use of natural gas imbalance service, when such instructions are issued consistent with the LDC's or pipeline's authority under a tariff, rate schedule or contract; (iii) consumption of natural gas during a period of authorized interruption of service by the relevant natural gas LDC or pipeline, determined in accordance with the terms of the applicable tariff, rate schedule or contract; or (iv) use of natural gas balancing services that are explicitly identified in the relevant natural gas LDC's or pipeline's applicable tariff, rate schedule or contract as unauthorized use or penalty gas.

23.3.1.4.6.2.1.2 If and to the extent a Market Party has obtained specific authorization from the relevant natural gas LDC or pipeline to use gas that would otherwise be unauthorized, such use shall not be considered unauthorized use by the ISO. Market Parties shall make every effort to clearly document authorization they obtain from the LDC or pipeline. Documentation obtained after the fact will be considered.

23.3.1.4.6.3 Screening of fuel type and fuel price information. The ISO may use automated processes and/or require manual review of fuel type and fuel price information submitted by Market Parties to test the accuracy of the information submitted in order to prevent market clearing prices and guarantee payments from being incorrectly calculated.

23.3.1.4.6.4 Consistent with the rules specified in this Section 23.3.1.4.6 of the Mitigation Measures and the procedures that the ISO develops to implement these rules, Market Parties shall notify the ISO of changes in fuel type or fuel price by (i) submitting revised fuel type or fuel price information to the ISO's Market Information System along with the Generator's Bid(s), or (ii) by directly contacting the ISO to request a reference level update consistent with ISO procedures, or (iii) by utilizing both of the available notification methods. Revised fuel type or fuel price information that exceeds, or is rejected based upon, the thresholds that the ISO uses to automatically screen fuel type or fuel price information that is submitted to the ISO's Market Information System along with a Generator's Bid(s) shall be submitted by directly contacting the ISO to request a reference level update, consistent with ISO procedures.

23.3.1.4.6.4.1 Exception—changes in fuel price or fuel type that are offered to support Incremental Energy or Minimum Generation Bids that exceed $1,000/MWh must be submitted in accordance with Section 23.7.3 (for a Generator) or Section 23.7.4 (for a Demand Side Resource) of these Mitigation Measures.

23.3.1.4.6.5 Following the completion of the ISO's automated and/or manual screening processes, the ISO shall use fuel type and fuel price information that Market Parties or their representatives submit to develop Generator reference levels unless (i) the information submitted is inaccurate, or (ii) the information was not timely submitted, and the Market Party's failure to timely submit the information is not excused by the ISO in accordance with Section 23.3.1.4.6.8 below, or (iii) consistent with Section 23.3.1.4.6.9 below.

23.3.1.4.6.6 The ISO may not always have sufficient time to complete its screening of proposed fuel type or fuel price changes prior to the relevant Day-Ahead Market day or Real-Time Market hour. *If* fuel type or fuel price information (i) is timely submitted or, where untimely, the submission of fuel type or fuel price information is excused in accordance with Section 23.3.1.4.6.8 below, and (ii) the fuel type or fuel price information that the Market Party submitted is proven to have been accurate or to have understated the actual cost incurred for that component, and (iii) the Bid(s) were tested using reference levels that reflected outdated fuel type and/or fuel price information and the Bid(s) were mitigated or a sanction was imposed pursuant to Section 23.4.3 of these Mitigation Measures, *then* the ISO shall (a) re-perform any test(s) that resulted in a sanction being imposed pursuant to Section 23.4.3 of these Mitigation Measures, using the accurate fuel type and/or fuel price information and use the revised results to calculate the appropriate sanction (if any), and (b) determine if the Bids for the Generator would have failed the relevant conduct test(s) if accurate fuel type and/or fuel price information had been used to develop reference levels. The ISO shall then restore any original (as-submitted) Bid(s) that would not have failed the relevant conduct test(s) if accurate fuel type and/or fuel price information had been used to develop the Generator's reference levels, and use the restored Bid(s) to determine a settlement. Otherwise the ISO shall use the Generator's correct or corrected reference level(s) to determine a settlement.

23.3.1.4.6.7 The ISO shall publicly post the thresholds it employs to automatically screen fuel type and fuel price information that is submitted to the ISO's Market Information System for potentially inaccurate fuel type and fuel price data inputs.

23.3.1.4.6.8 For purposes of this Section 23.3.1.4.6, "timely" notice or submission to the Real-Time Market shall mean the submission of fuel type and/or fuel price information using the methods specified in Section 23.3.1.4.6.4 of these Mitigation Measures prior to market close for the relevant Real-Time Market hour. For purposes of this Section 23.3.1.4.6, "timely" notice or submission to the Day-Ahead Market shall mean the submission of fuel type and/or fuel price information using the methods specified in Section 23.3.1.4.6.4 of these Mitigation Measures at least 15 minutes prior to the close of the Day-Ahead Market (*i.e.*, by 4:45 a.m.). Market Parties are not expected to submit invoices or other supporting data with their Day-Ahead Market or Real-Time Market fuel type and fuel price information, but are expected to retain invoices and other supporting data consistent with the data retention requirements set forth in the Plan, and to be able to produce such information within a reasonable timeframe when asked to do so by the ISO or by its Market Monitoring Unit.

It may not always be possible for a Market Party to timely update a Generator's fuel type or fuel price to reflect unexpected real-time changes or events in advance of the first affected market-hour. Upon a showing of extraordinary circumstances, the ISO may retroactively reflect in Real-Time Market reference levels fuel type or fuel price information that was not timely submitted by a Market Party. While it should ordinarily be possible for a Market Party to timely submit updated fuel type and fuel price information for use in developing a Generator's Day-Ahead Market reference levels, the ISO may retroactively accept and utilize late-submitted Day-Ahead Market fuel type or fuel price information upon a showing of extraordinary circumstances.

23.3.1.4.6.8.1 Exception—changes in fuel price or fuel type that are offered to support Incremental Energy or Minimum Generation Bids that exceed $1,000/MWh must be submitted in accordance with the submission deadlines specified in Section 23.7.3 (for a Generator) or Section 23.7.4 (for a Demand Side Resource) of these Mitigation Measures.

23.3.1.4.6.9 If (i) the ISO determines, following consultation with the Market Party and review by the Market Monitoring Unit, that the Market Party or its representative has submitted inaccurate fuel type or fuel price information that was biased in the Market Party's favor, or (ii) if a Market Party is subject to a penalty or sanction under Section 23.4.3.3.3 of these Mitigation Measures for submitting inaccurate fuel price or fuel type information, *then* the ISO shall cease using the fuel type and fuel price information submitted to the ISO's Market Information System along with the Generator's Bid(s) to develop reference levels for the affected Generator(s) in the relevant (Day-Ahead or real-time) market for the duration(s) set forth below, unless the Market Party demonstrates to the ISO that the questioned conduct is consistent with competitive behavior.

23.3.1.4.6.9.1 The first time the ISO ceases using the fuel type and fuel price information submitted to the ISO's Market Information System along with the Bid(s) for a Generator to develop Day-Ahead or real-time reference levels for that Generator, it shall do so for 30 days. The 30-day period shall start two business days after the date that the ISO provides written notice of its determination that the application of mitigation is required.

23.3.1.4.6.9.2 Subject to Section 23.3.1.4.6.9.3 below, the second time the ISO ceases using the fuel type and fuel price information submitted to the ISO's Market Information System along with the Bid(s) for a Generator to develop Day-Ahead or real-time reference levels for that Generator, it shall do so for 60 days. The 60-day period shall start two business days after the date that the ISO provides written notice of its determination that the application of mitigation is required. Subject to Section 23.3.1.4.6.9.3 below, any subsequent time the ISO ceases using the fuel type and fuel price information submitted to the ISO's Market Information System along with the Bid(s) for a Generator to develop Day-Ahead or real-time reference levels for that Generator, it shall do so for 120 days. The 120-day period shall start two business days after the date that the ISO provides written notice of its determination that the application of mitigation is required.

23.3.1.4.6.9.3 If the bidders of a Generator that has previously been mitigated under this Section 23.3.1.4.6.9 becomes and remains continuously eligible to submit fuel type and fuel price information in the Day-Ahead or Real-Time Market (as appropriate) for a period of one year or more, then the ISO shall apply the mitigation measure set forth in Section 23.3.1.4.6.9 of the Mitigation Measures as if the Generator had not previously been subject to the mitigation measure.

23.3.1.4.6.9.4 Market Parties that transfer, sell, assign, or grant to another Market Party the right or ability to Bid a Generator that is subject to the mitigation measure described in this Section 23.3.1.4.6.9 are required to inform the new Market Party that the Generator has been mitigated under this measure, and to inform the new Market Party of the expected duration of such mitigation.

23.3.1.4.6.9.5 For purposes of this Section 23.3.1.4.6.9, submitted fuel type information shall be considered biased in a Market Party's favor if (a) the Market Party submitted revised fuel type information for a Generator for at least 100 hours during the previous 90 days, and (b) for at least one hour the fuel type that a Market Party submits for the Generator is not the most economic fuel type available to the Generator, taking into consideration fuel availability, operating conditions, and relevant regulatory or reliability requirements, and (c) as a result of the change(s) in fuel type, the fuel prices that the ISO uses to develop reference levels for a Generator exceeded the fuel price that the ISO would have used to develop reference levels for that Generator by greater than the higher of 10% or $0.50/MMBtu, on average, over the previous 90 days. For purposes of calculating the average, only hours in which the Market Party changed the Generator's fuel type to a more expensive fuel type will be considered. The Day-Ahead and Real-Time Markets shall be considered separately for purposes of this analysis.

23.3.1.4.6.9.6 For purposes of this Section 23.3.1.4.6.9, submitted fuel price information shall be considered biased in a Market Party's favor if (a) the Market Party submitted revised fuel price information for a Generator for at least 100 hours during the previous 90 days, and (b) the fuel price that the Market Party submitted to the ISO's Market Information System for use in developing reference levels for a Generator exceeded the greater of the actual fuel price (as substantiated by supplier quotes or invoices) or the ISO’s indexed fuel price, by greater than the higher of 10% or $0.50/MMBtu, on average, over the previous 90 days. For purposes of calculating the average, only hours in which the fuel price submitted exceeds the ISO’s indexed fuel price will be considered. The Day-Ahead and Real-Time Markets shall be considered separately for purposes of this analysis.

23.3.1.4.6.9.7 The responsibilities of the Market Monitoring Unit that are addressed in Section 23.3.1.4.6.9 of the Mitigation Measures are also addressed in Section 30.4.6.2.3 of the Plan.

23.3.1.4.6.10 In order to adjust (i) Bid-based incremental energy, minimum generation and start-up reference levels, and (ii) LBMP-based incremental energy and minimum generation reference levels to more accurately reflect fuel costs, the ISO may calculate distinct Bid- and LBMP-based reference levels for each fuel type or blend of fuel types that a Generator is capable of burning, and shall fuel index each of the distinct Bid- or LBMP-based reference levels that it calculates for fuel types that are amenable to fuel indexing. Where a Generator can draw on multiple natural gas sources that each have distinct, posted, market clearing prices, the ISO may calculate distinct Bid-Based or LBMP-based reference levels for each such available supply source.

23.3.1.4.7 Except as otherwise authorized in accordance with Section 23.3.1.4.6.8 above, Market Parties shall timely report significant changes to the cost components used to develop their Generator’s reference levels to the ISO in order to permit the revised costs to be timely reflected in the Generator reference levels.

However, if the ISO uses published index prices to fuel index a Generator's reference level when that Generator is burning a fuel type that is amenable to fuel indexing (which may include a blend of two indexed fuel types), the Market Party is not required to report fuel prices that are less than the published index price that the ISO relies on.

23.3.1.4.8 Reflecting opportunity costs in Reference Levels. The ISO shall use the information available to it to adjust reference levels to reflect appropriate opportunity costs.

23.3.1.4.8.1 Prohibition of duplicative and evasive cost submissions and Bids. Costs that are submitted or Bid as fuel costs shall not also be submitted or Bid as opportunity costs. A cost shall not be submitted or Bid in two parts, as both a fuel costs and an opportunity cost, in order to evade applicable screening thresholds. Fossil generators shall not submit or Bid fuel costs, including but not limited to balancing costs, as opportunity costs. Energy Storage Resources shall not submit or Bid the cost they expect to incur to withdraw Energy as a fuel cost.

If the ISO identifies a potentially duplicative or evasive Bid or cost submission that appears to violate this prohibition, it shall inform the Market Monitoring Unit of the potential Market Violation.

23.3.1.4.8.2 ISO Reporting Obligation. If the ISO did not adjust reference levels to reflect timely (as that term is defined in Section 23.3.1.4.8.9 below) submitted, appropriate opportunity costs, and the ISO's failure to adjust reference levels to reflect such opportunity costs affected market clearing prices or had an impact on guarantee payments that cannot be corrected, then the ISO shall report any market clearing price and uncorrected guarantee payment impacts to FERC staff and to its Market Participants. The ISO is not required to report, or to otherwise act, if no market impact is identified.

23.3.1.4.8.3 Market Parties shall monitor Generator reference levels and shall endeavor to timely (as that term is defined in Section 23.3.1.4.8.9 below) contact the ISO to request an adjustment to a Generator's reference level(s) when changes in opportunity costs are expected to impact the Generator's reference levels.

23.3.1.4.8.4 Screening of opportunity cost submissions. The ISO may use automated processes and/or require manual review of opportunity cost submissions by Market Parties in order to prevent market clearing prices and guarantee payments from being incorrectly calculated.

23.3.1.4.8.5 Consistent with the rules specified in this Section 23.3.1.4.8 of the Mitigation Measures and the procedures that the ISO develops to implement these rules, Market Parties shall notify the ISO of changes in opportunity costs by (i) submitting revised opportunity cost information to the ISO's Market Information System along with the Generator's Bid(s), or (ii) by directly contacting the ISO to request a reference level update consistent with ISO procedures, or (iii) by utilizing both of the available notification methods. Revised opportunity cost information that exceeds, or is rejected based upon, the thresholds that the ISO uses to automatically screen opportunity cost information that is submitted to the ISO's Market Information System along with a Generator's Bid(s) shall be submitted by directly contacting the ISO to request a reference level update, consistent with ISO procedures.

23.3.1.4.8.6 Following the completion of the ISO's automated and/or manual screening processes, the ISO shall use opportunity cost information that Market Parties or their representatives submit to develop Generator reference levels unless (i) the information submitted is inaccurate, or (ii) the information was not timely submitted, and the Market Party's failure to timely submit the information is not excused by the ISO in accordance with Section 23.3.1.4.8.9 below.

23.3.1.4.8.7 The ISO may not always have sufficient time to complete its screening of proposed opportunity cost changes prior to the relevant Day-Ahead Market day or Real-Time Market hour. *If* opportunity cost information (i) is timely submitted or, where untimely, the submission is excused in accordance with Section 23.3.1.4.8.9 below, and (ii) the opportunity cost information that the Market Party submitted is proven to have been accurate or to have understated the actual cost incurred for that component, and (iii) the Bid(s) were tested using reference levels that reflected outdated opportunity cost information and the Bid(s) were mitigated or a sanction was imposed pursuant to Section 23.4.3 of these Mitigation Measures, *then* the ISO shall (a) re-perform any test(s) that resulted in a sanction being imposed pursuant to Section 23.4.3 of these Mitigation Measures, using the accurate opportunity cost information and use the revised results to calculate the appropriate sanction (if any), and (b) determine if the Bids for the Generator would have failed the relevant conduct test(s) if accurate opportunity cost information had been used to develop reference levels. The ISO shall then restore any original (as-submitted) Bid(s) that would not have failed the relevant conduct test(s) if accurate opportunity cost information had been used to develop the

Generator's reference levels, and use the restored Bid(s) to determine a settlement. Otherwise the ISO shall use the Generator's correct or corrected reference level(s) to determine a settlement.

23.3.1.4.8.8 The ISO shall publicly post the thresholds it employs to automatically screen opportunity cost information that is submitted to the ISO's Market Information System for inputs that require manual review before they can be permitted to take effect.

23.3.1.4.8.9 For purposes of this Section 23.3.1.4.8, "timely" notice or submission to the Real-Time Market shall mean the submission of opportunity cost information using the methods specified in Section 23.3.1.4.8.5 of these Mitigation Measures prior to market close for the relevant Real-Time Market hour. For purposes of this Section 23.3.1.4.8, "timely" notice or submission to the Day-Ahead Market shall mean the submission of opportunity cost information using the methods specified in Section 23.3.1.4.8.5 of these Mitigation Measures prior to the close of the Day-Ahead Market. Market Parties are not expected to submit supporting data with their Bids that include revised opportunity cost information, but are expected to retain a record of how the submitted opportunity cost was determined and other supporting data consistent with the data retention requirements set forth in the Plan, and to be able to produce such information within a reasonable timeframe when asked to do so by the ISO or by its Market Monitoring Unit.

It may not always be possible for a Market Party to timely update a Generator's opportunity cost to reflect unexpected real-time changes or events in advance of the first affected market-hour. Upon a showing of extraordinary circumstances, the ISO may retroactively reflect in Real-Time Market reference levels opportunity cost information that was not timely submitted by a Market Party. While it should ordinarily be possible for a Market Party to timely submit updated opportunity cost information for use in developing a Generator's Day-Ahead Market reference levels, the ISO may retroactively accept and utilize late-submitted Day-Ahead Market opportunity cost information upon a showing of extraordinary circumstances.

23.3.2 Material Price Effects or Changes in Guarantee Payments

23.3.2.1 Market Impact Thresholds

In order to avoid unnecessary intervention in the ISO Administered Markets, Mitigation Measures shall not be imposed unless conduct identified as specified above (i) causes or contributes to a material change in one or more prices in an ISO Administered Market, or (ii) substantially increases guarantee payments to participants in the New York Electric Market. Initially, the thresholds to be used by the ISO to determine a material price effect or change in guarantee payments shall be:

23.3.2.1.1 an increase of 200 percent or $100 per MWh, whichever is lower, in the hourly Day-Ahead or Real-Time Energy LBMP at any location, or of any other price in an ISO Administered Market; or

23.3.2.1.2 an increase of 200 percent, or 50 percent for Generators in a Constrained Area in Bid Production Cost guarantee payments to a Market Party for a Generator for a day; or

23.3.2.1.3 for a Constrained Area Generator subject to either a Real-Time Market or Day-Ahead Market conduct threshold, as specified above in Sections 23.3.1.1.1, 23.3.1.2.2.1, or 23.3.1.2.2.3: for all Constrained Hours (as defined in Section 23.3.1.2.2.1 for the Real-Time Market and in Section 23.3.1.2.2.3 for the Day-Ahead Market) for the unit being Bid, a threshold determined in accordance with the formula specified in Section 23.3.1.2.2.1 for the Real-Time Market or Section 23.3.1.2.2.3 for the Day-Ahead Market.

23.3.2.2 Price Impact Analysis

23.3.2.2.1 When it has the capability to do so, the ISO shall determine the effect on prices or guarantee payments of questioned conduct through the use of sensitivity analyses performed using the ISO's SCUC, RTC and RTD computer models, and such other computer modeling or analytic methods as the ISO shall deem appropriate following consultation with its Market Monitoring Unit. The responsibilities of the Market Monitoring Unit that are addressed in this section of the Mitigation Measures are also addressed in Section 30.4.6.2.4 of Attachment O.

23.3.2.2.2 Pending development of the capability to use automated market models, the ISO, following consultation with its Market Monitoring Unit, shall determine the effect on prices or guarantee payments of questioned conduct using the best available data and such models and methods as they shall deem appropriate. The responsibilities of the Market Monitoring Unit that are addressed in this section of the Mitigation Measures are also addressed in Section 30.4.6.2.5 of Attachment O.

23.3.2.2.3 The ISO shall implement automated procedures within the SCUC for Constrained Areas, and within RTC for Constrained Areas. Such automated procedures will: (i) determine whether any Day-Ahead or Real-Time Energy Bids, including start-up costs Bids and Minimum Generation Bids but excluding Ancillary Services Bids and Bids that only violate the conduct thresholds specified in Sections 23.3.1.2.1.1.2(b) or 23.3.1.2.2.6(b) of these Mitigation Measures, that have not been adequately justified to the ISO exceed the thresholds for economic withholding specified in Section 23.3.1.2 above; and, if so, (ii) determine whether such Bids would cause material price effects or changes in guarantee payments as specified in Section 23.3.2.1.

23.3.2.2.4 The ISO shall forgo performance of the additional SCUC and RTC passes necessary for automated mitigation of Bids in a given Day-Ahead Market or Real-Time Market if evaluation of unmitigated Bids results in prices at levels at which it is unlikely that the thresholds for Bid mitigation will be triggered.

23.3.2.3 Section 205 Filings

The ISO shall make a filing under § 205 with the Commission seeking authorization to apply an appropriate mitigation measure to conduct that departs significantly from the conduct that would be expected under competitive market conditions but does not rise to the thresholds specified in Sections 23.3.1.1 through 23.3.1.3 above if that conduct has a significant effect on market prices or guarantee payments as specified below, unless the ISO determines, from information provided by the Market Party or Parties (which may include a Demand Side Resource participating in the Operating Reserves or Regulation Service Markets) that would be subject to mitigation, or from other information available to the ISO that the conduct and associated price or guarantee payment effect(s) are attributable to legitimate competitive market forces or incentives. For purposes of this section, conduct shall be deemed to have an effect on market prices or guarantee payments that is significant if it exceeds one of the following thresholds:

23.3.2.3.1 an increase of 100 percent in the hourly day-ahead or real-time energy LBMP at any location, or of any other price in an ISO Administered Market; or

23.3.2.3.2 an increase of 100 percent in Bid Production Cost guarantee payments to a Market Party for a Generator for a day, or an increase of 100 percent in any other guarantee payment over the time period used by the ISO to calculate the guarantee payment.

23.3.3 Consultation with a Market Party

23.3.3.1 Consultation Process

23.3.3.1.1 *Consultation initiated by the ISO to determine if mitigation is appropriate:* Applies to Market-Party-specific and/or Generator-specific mitigation, but not to mitigation that is applied pursuant to Sections 23.3.1.2.3, 23.3.2.2.3, or 23.5.2 of these mitigation measures. If through the application of an appropriate index or screen or other monitoring of market conditions, conduct is identified that (i) exceeds an applicable threshold, and (ii) has a material effect, as specified above, on one or more prices or guarantee payments in an ISO Administered Market, the ISO shall, as and to the extent specified in Attachment O or in Section 23.3.3.2 of these Mitigation Measures, contact the Market Party engaging in the identified conduct to request an explanation of the conduct.

23.3.3.1.2 *Consultation initiated by a Market Party when it anticipates that its Generator's marginal costs or other Bid parameters may exceed the Generator's reference level(s) by more than the relevant threshold(s).* If a Market Party anticipates submitting Bids in a market administered by the ISO that will exceed the thresholds specified in Section 23.3.1

above for identifying conduct inconsistent with competition, the Market Party may contact the ISO to provide an explanation of any legitimate basis for any such changes in the Market Party's Bids.

23.3.3.1.3 *Results of consultation process addressing Bids.* If a Market Party's explanation of the reasons for its bidding indicates to the satisfaction of the ISO that the questioned conduct is consistent with competitive behavior, no further action will be taken. A preliminary determination by the ISO shall be provided to the Market Monitoring Unit for its review and comment.

23.3.3.1.4 *Consultation initiated by a Market Party regarding reference levels.* Upon request, the ISO shall consult with a Market Party or its representative with respect to the information and analysis used to determine reference levels under Section 23.3.1.4 for that Market Party's Generator(s). If cost data or other information submitted by a Market Party's Generator(s) indicates to the satisfaction of the ISO that the reference levels for that Market Party should be changed, revised reference levels shall be proposed by the ISO, communicated to the Market Monitoring Unit for its review and comment and, following the ISO's consideration of any recommendations that the Market Monitoring Unit is able to timely provide, communicated to the Market Party, and implemented by the ISO as soon as practicable. Changes to the reference levels addressed pursuant to the terms of this Section 23.3.3.1.4 shall be implemented on a going-forward basis commencing no earlier than the date that the Market Party's consultation request is received. The responsibilities of the Market Monitoring Unit that are addressed in this section of the Mitigation Measures are also addressed in Section 30.4.6.2.6 of Attachment O.

23.3.3.1.5 *Information required to support consultation regarding Bids and reference levels.* Market Parties shall ensure that the information they submit to the ISO, including but not limited to fuel price and fuel type information, is accurate. Except as set forth in Section 23.3.1.4.6.8, the ISO may not retroactively revise a reference level to reflect additional fuel costs if a Market Party or its representative did not timely submit accurate fuel cost information. Unsupported speculation by a Market Party does not present a valid basis for the ISO to determine that Bids that a Market Party submitted are consistent with competitive behavior, or to determine that submitted costs are appropriate for inclusion in the ISO's development of reference levels. Consistent with Sections 30.6.2.2 and 30.6.3.2 of the Plan, the Market Party shall retain the documents and information supporting its Bids and the costs it proposes to include in reference levels.

23.3.3.2 Consultation Requirements

23.3.3.2.1 The ISO shall make a reasonable attempt to contact and consult with the relevant Market Party about the Market Party's reference level(s) before imposing conduct and impact mitigation, other than conduct and impact mitigation imposed through the automated procedures described in Section 23.3.2.2.3 of these Mitigation Measures. The ISO shall keep records documenting its efforts to contact and consult with the Market Party.

23.3.3.2.2 Consultation regarding both real-time guarantee payment mitigation and mitigation of Generators committed outside the economic evaluation process in the Day-Ahead or Real-Time Markets to protect or preserve system reliability in accordance with Section 23.3.1.2.3 of these Mitigation Measures is addressed in Section 23.3.3.3, below. Consultation regarding Day-Ahead guarantee payment mitigation of Generators, other than mitigation imposed through the automated procedures described in Section 23.3.2.2.3 of these Mitigation Measures, shall be conducted in accordance with Sections 23.3.3.1 and 23.3.3.2 of these Mitigation Measures.

23.3.3.3 Consultation Rules for Real-Time Guarantee Payment Mitigation

23.3.3.3.1 Real-Time Guarantee Payment Consultation Process

23.3.3.3.1.1 For real-time guarantee payment mitigation determined pursuant to Sections 23.3.1.2.1 or 23.3.1.2.2, and 23.3.2.1.2 of these Mitigation Measures, the ISO shall electronically post settlement results informing Market Parties of Bid(s) that failed the real-time guarantee payment impact test. The settlement results posting shall include the adjustment to the guarantee payment and the mitigated Bid(s). The initial posting of settlement results ordinarily occurs two days after the relevant real-time market day.

23.3.3.3.1.2 For real-time guarantee payment mitigation determined pursuant to Sections 23.3.1.2.1 or 23.3.1.2.2, and 23.3.2.1.2 of these Mitigation Measures, no more than two business days after new or revised real-time guarantee payment impact test settlement results are posted, the ISO will send an e-mail or other notification to all potentially impacted Market Parties that comply with Section 23.3.3.3.1.2.2 of these Mitigation Measures.

23.3.3.3.1.2.1 Although the ISO is authorized to take up to two business days to provide notification to all potentially impacted Market Parties that comply with Section 23.3.3.3.1.2.2 of these Mitigation Measures, the ISO shall undertake reasonable efforts to provide notification to such Market Parties within one business day after new or revised real-time guarantee payment impact test settlement results are posted.

23.3.3.3.1.2.2 A Market Party that desires to receive notification from the ISO must provide one e-mail address to the ISO for real-time guarantee payment mitigation notices. Each Market Party is responsible for maintaining and monitoring the e-mail address it provides, and informing the ISO of any change(s) to that e-mail address in order to continue to receive e-mail notification. E-mail will be the ISOs primary method of providing notice to Market Parties.

23.3.3.3.1.2.3 Regardless of whether a Market Party chooses to receive notification from the ISO, each Market Party is responsible for reviewing its posted real-time guarantee payment impact test settlement results and for contacting the ISO to request a consultation if and when appropriate.

23.3.3.3.1.3 The following notice rules apply to guarantee payment mitigation determined pursuant to Section 23.3.1.2.3 of these Mitigation Measures.

23.3.3.3.1.3.1 For mitigation of a Generator’s Minimum Generation Bid, Start-Up Bid or Incremental Energy Bid resulting from its DARU or SRE commitment, the ISO shall send an e-mail or other notification to potentially impacted Market Parties that comply with Section 23.3.3.3.1.2.2 of these Mitigation Measures within ten business days after the relevant market day, and shall undertake reasonable efforts to provide notification to such Market Parties within two business days after the relevant market day. The e-mail shall identify the date of the proposed mitigation and the Bid(s) or Bid components that the NYISO proposes to mitigate for all or part of the relevant market day.

As soon as it is able to do so, the NYISO will commence electronically posting settlement results informing Market Parties of Bid(s) that failed the Section 23.3.1.2.3 test and sending an e-mail or other notification to potentially impacted Market Parties that comply with Section 23.3.3.3.1.2.2 of these Mitigation Measures. The settlement results posting shall include the mitigated bid(s). The posting of settlement results ordinarily occurs two days after the relevant real-time market day.

23.3.3.3.1.3.2 For mitigation of a Generator's Minimum Generation Bid, Start-Up Bid or Incremental Energy Bid resulting from an Out-of-Merit dispatch above the Generator's DARU or SRE commitment, the ISO shall send an e-mail or other notification to potentially impacted Market Parties that comply with Section 23.3.3.3.1.2.2 of these Mitigation Measures within 10 business days after the relevant market day. The e-mail shall identify the date of the proposed mitigation and the bid(s) or bid components that the NYISO proposes to mitigate for all or part of the relevant market day.

23.3.3.3.1.3.3 For mitigation based on a Generator's minimum run time, start-up time, minimum down time, minimum generation MWs, or maximum number of stops per day, or for mitigation based on temporal or operating parameters related to the withdrawal and injection of Energy by Withdrawal-Eligible Generators, the ISO shall send an e-mail or other notification to potentially impacted Market Parties that comply with Section 23.3.3.3.1.2.2 of these Mitigation Measures within 10 business days after the relevant market day. The e-mail shall identify the date of the proposed mitigation and the conduct failing Bid(s) or Bid components.

23.3.3.3.1.4 Market Parties that want to consult with the ISO regarding real-time guarantee payment impact test results, or regarding mitigation applied in accordance with Section 23.3.1.2.3 of these Mitigation Measures, for a particular market day must submit a written request to initiate the consultation process that specifies the market day and Bid(s) for which consultation is being requested (for purposes of this Section 23.3.3.3.1, a "Consultation Request").

23.3.3.3.1.4.1 Consultation Requests must be received by the ISO's customer relations department within 15 business days after the ISO (i) posts new or revised real-time guarantee payment impact test settlement results, or (ii) either posts new or revised real-time guarantee payment impact test settlement results or sends an e-mail informing a Market Party of the results of a test performed pursuant to Section 23.3.1.2.3 of these Mitigation Measures for the relevant market day. Consultation Requests received outside the 15 business day period shall be rejected by the ISO.

23.3.3.3.1.4.2 The ISO may send more than one notice informing a Market Party of the same instance of mitigation. Notices that identify real-time guarantee payment impact test or Section 23.3.1.2.3 mitigation settlement results that are not new (for which the Market Party has already received a notice from the ISO) and that do not reflect revised mitigation (for which the dollar impact of the real-time guarantee payment mitigation has not changed) shall not present an additional opportunity, or temporally extend the opportunity, for the Market Party to initiate consultation.

23.3.3.3.1.4.3 If consultation was timely requested and completed addressing a particular set of real-time guarantee payment impact test results, or addressing a particular instance of mitigation applied in accordance with Section 23.3.1.2.3 of these Mitigation Measures, a Market Party may not again request consultation regarding the same real-time guarantee payment impact test results, or the same application of Section 23.3.1.2.3 mitigation, unless revised settlement results, that are not due to the previously completed consultation and that change the dollar impact of the relevant instance of mitigation, are posted.

23.3.3.3.1.5 The Consultation Request may include: (i) an explanation of the reason(s) why the Market Party believes some or all of the reference levels used by the ISO for the market day(s) in question are inappropriate, or why some or all of the Market Party's Bids on the market day(s) in question were otherwise consistent with competitive behavior; and (ii) supporting documents, data and other relevant information (collectively, for purposes of this Section 23.3.3.3.1, "Data"), including proof of any cost(s) claimed.

23.3.3.3.1.5.1 Market Parties shall ensure that the information they submit to the ISO, including but not limited to fuel price and fuel type information, is accurate. Except as set forth in Section 23.3.1.4.6.8, the ISO may not retroactively revise a reference level to reflect additional fuel costs if a Market Party or its representative did not timely submit accurate fuel cost information. Except as set forth in Section 23.3.1.4.8.9, the ISO may not retroactively revise a reference level to reflect additional opportunity costs if a Market Party or its representative did not timely submit accurate opportunity cost information.

23.3.3.3.1.6 If the Market Party is not able to provide (i) an explanation of the reason(s) why the Market Party believes some or all of the reference levels used by the ISO for the market day(s) in question are inappropriate, or why some or all of the Market Party's Bids on the market day(s) in question were otherwise consistent with competitive behavior, or (ii) all supporting Data, at the time a Consultation Request is submitted, the Market Party should specifically identify any additional explanation or Data it intends to submit in support of its Consultation Request and provide an estimate of the date by which it will provide the additional explanation or Data to the ISO.

23.3.3.3.1.7 Following the submission of a Consultation Request that satisfies the timing and Bid identification requirements of Section 23.3.3.3.1.4, above, consultation shall be performed in accordance with Section 23.3.3.1 of these Mitigation Measures, as supplemented by the following rules:

23.3.3.3.1.7.1 The ISO shall consult with the Market Party to determine whether the information available to the ISO presents an appropriate basis for (i) modifying the reference levels used to perform real-time guarantee payment mitigation for the market day in question, or (ii) determining that the Market Party's Bid(s) on the market day in question were consistent with competitive behavior. The ISO shall only modify the reference levels used to perform mitigation, or determine that the Market Party's Bid(s) on the market day that is the subject of the

Consultation Request were consistent with competitive behavior, if the ISO has in its possession Data that is sufficient to support such a decision.

23.3.3.3.1.7.2 A preliminary determination by the ISO shall be provided to the Market Monitoring Unit for its review and comment, and the ISO shall consider the Market Monitoring Unit's recommendations in reaching its decision. The ISO shall inform the Market Party of its decision, in writing, as soon as reasonably practicable, but in no event later than (i) 50 business days after the new or revised real-time guarantee payment impact test settlement results for the relevant market day were posted, or (ii) 50 business days after the earlier of the posting of new or revised Section 23.3.1.2.3 mitigation settlement results for the relevant market day, or the issuance of an e-mail in accordance with Section 23.3.3.3.1.3, above. If the ISO does not affirmatively determine that it is appropriate to modify the Bid(s) that are the subject of the Consultation Request within 50 business days, the Bid(s) shall remain mitigated. The responsibilities of the Market Monitoring Unit that are addressed in this section of the Mitigation Measures are also addressed in Section 30.4.6.2.7 of Attachment O.

23.3.3.3.1.7.3 The ISO may, as soon as practicable, but at any time within the consultation period, request Data from the Market Party. The Market Party is expected to undertake all reasonable efforts to provide the requested Data as promptly as possible, to inform the ISO of the date by which it expects to provide requested Data, and to promptly inform the ISO if the Market Party does not intend to, or cannot, provide Data that has been requested by the ISO.

23.3.3.3.1.8 This Section 23.3.3.3.1 addresses Consultation Requests. It is not intended to limit, alter or modify a Market Party's ability to submit or proceed with a billing dispute pursuant to Section 7.4 of the ISO Services Tariff or Section 2.7.4.1 of the ISO OATT.

23.3.3.3.2 Revising Reference Levels of Certain Generators Committed Out-of-Merit or via Supplemental Resource Evaluation for Conducting Real-Time Guarantee Payment Conduct and Impact Tests and Applying Mitigation in Accordance with Section 23.3.1.2.3 of these Mitigation Measures

23.3.3.3.2.1 Consistent with and subject to all of the requirements of Section 23.3.3.3.1 of these Mitigation Measures, Generators that (i) are committed Out-of-Merit or via a Supplemental Resource Evaluation after the DAM has posted, and (ii) for which the NYISO has posted real-time guarantee payment impact test settlement results, or identified possible mitigation under Section 23.3.1.2.3 of these Mitigation Measures may contact the ISO within 15 business days after new or revised impact test settlement results are posted, or possible mitigation under Section 23.3.1.2.3 of these Mitigation Measures is identified, to request that the reference levels used to perform the testing and mitigation be adjusted to include any of the following verifiable costs:

23.3.3.3.2.1.1 procuring fuel at prices that exceed the index prices used to calculate the Generator's reference level;

23.3.3.3.2.1.2 burning a type of fuel or blend of fuels that is not reflected in the Generator's reference level;

23.3.3.3.2.1.3 permitted gas balancing charges;

23.3.3.3.2.1.4 compliance with operational flow orders;

23.3.3.3.2.1.5 purchasing additional emissions allowances that are necessary to satisfy the Generator's Supplemental Resource Evaluation or Out-of-Merit schedule; and

23.3.3.3.2.1.6 demonstrated opportunity costs that differ from the opportunity cost used in calculating the Generator's reference level.

23.3.3.3.2.2 The six categories of verifiable costs specified above shall be used to modify the requesting Generator's reference level(s) subject to the following prerequisites:

23.3.3.3.2.2.1 the Generator must specifically and accurately identify and document the extraordinary costs it has incurred to operate during the hours of its Supplemental Resource Evaluation or Out-of-Merit commitment; and

23.3.3.3.2.2.2 the costs must not already be reflected in the Generator's reference levels or be recovered from the ISO through other means.

As soon as practicable after the Market Party demonstrates to the ISO's reasonable satisfaction that one or more of the five categories of extraordinary costs have been incurred, but in no event later than the deadline set forth in Section 23.3.3.3.1.7.2 of these Mitigation Measures, the ISO shall adjust the affected Generator's reference levels and re-perform the real-time guarantee payment conduct and impact tests, or the Section 23.3.1.2.3 test, as appropriate, for the affected day. Only the reference levels used to perform real-time guarantee payment mitigation and/or mitigation pursuant to Section 23.3.1.2.3 of these Mitigation Measures, will be adjusted.

23.3.3.3.2.3 If, at some point prior to the issuance of a Close-Out Settlement for the relevant service month, the ISO or the Commission determine that some or all of the costs claimed by the Market Party during the consultation process described above were not, in fact, incurred over the course of the Out-of-Merit or Supplemental Resource Evaluation commitment, or were recovered from the ISO through other means, the ISO shall re-perform the appropriate test(s) using reference levels that reflect the verifiable costs that the Generator incurred and shall apply mitigation if the Generator's Bids fail conduct and impact, or the Section 23.3.1.2.3 test, at the corrected reference levels.

23.3.3.3.2.4 Generators may contact the ISO to request the inclusion of costs other than the six types identified above in their reference levels. The ISO shall consider such requests in accordance with Sections 23.3.1.4, or 23.3.3.3.1 of these Mitigation Measures, as appropriate.