

Attachment II

2.12 Definitions - L

LBMP Market(s): The Real-Time Market or the Day-Ahead Market or both.

Limited Control Run-of-River Hydro Resource: A Generator above 1 MW in size that has demonstrated to the satisfaction of the ISO that its Energy production depends directly on river flows over which it has limited control and that such dependence precludes accurate prediction of the facility's real-time output.

Limited Customer: An entity that is not a Customer but which qualifies to participate in the ISO's Emergency Demand Response Program by complying with Limited Customer requirements set forth in the ISO Procedures.

Limited Energy Storage Resource ("LESR"): A Generator authorized to offer Regulation Service only and characterized by limited Energy storage, that is, the inability to sustain continuous operation at maximum Energy withdrawal or maximum Energy injection for a minimum period of one hour. LESRs must bid as ISO-Committed Flexible Resources.

Limited Energy Storage Resource ("LESR") Energy Management: Real-time Energy injections or withdrawals scheduled by the ISO to manage the Energy storage capacity of a Limited Energy Storage Resource, pursuant to ISO Procedures, for the purpose of maximizing the Capacity bid as available for Regulation Service from such Resource.

Linden VFT Scheduled Line: A transmission facility that interconnects the NYCA to the PJM Interconnection, L.L.C. Control Area in Linden, New Jersey.

LIPA Tax Exempt Bonds: Obligations issued by the Long Island Power Authority, the interest on which is not included in gross income under the Internal Revenue Code.

Load: A term that refers to either a consumer of Energy or the amount of demand (MW) or Energy (MWh) consumed by certain consumers. Energy withdrawals by Withdrawal-Eligible Generators are not Load.

Load Serving Entity ("LSE"): Any entity, including a municipal electric system and an electric cooperative, authorized or required by law, regulatory authorization or requirement, agreement, or contractual obligation to supply Energy, Capacity and/or Ancillary Services to retail customers located within the NYCA, including an entity that takes service directly from the ISO to supply its own Load in the NYCA.

Load Shedding: The systematic reduction of system demand by disconnecting Load in response to a Transmission System or area Capacity shortage, system instability, or voltage control considerations under the ISO OATT.

Load Zone: One (1) of eleven (11) geographical areas located within the NYCA that is bounded by one (1) or more of the fourteen (14) New York State Interfaces.

Local Furnishing Bonds: Tax-exempt bonds issued by a Transmission Owner under an agreement between the Transmission Owner and the New York State Energy Research and Development Authority (“NYSERDA”), or its successor, or by a Transmission Owner itself, and pursuant to Section 142(f) of the Internal Revenue Code, 26 U.S.C. § 142(f).

Local Generator: A resource operated by or on behalf of a Load that is either: (i) not synchronized to a local distribution system; or (ii) synchronized to a local distribution system solely in order to support a Load that is equal to or in excess of the resource’s Capacity. Local Generators supply Energy only to the Load they are being operated to serve and do not supply Energy to the distribution system.

Locality: A single LBMP Load Zone or set of adjacent LBMP Load Zones within which a minimum level of Installed Capacity must be maintained, and as specifically identified in this subsection to mean (1) Load Zone J; (2) Load Zone K; and (3) Load Zones G, H, I, and J collectively (*i.e.*, the G-J Locality).

Locality Exchange Factor: The percentage of Locational Export Capacity that the ISO determines annually in accordance with Section 5.11.6 of the Services Tariff.

Locality Exchange MW: The MW of Locational Export Capacity excluding the MW to be transmitted using UDRs, that the ISO determines in accordance with Section 5.11.5 of the Services Tariff.

Local Reliability Rule: A Reliability Rule established by a Transmission Owner, and adopted by the NYSRC, to meet specific reliability concerns in limited areas of the NYCA, including without limitation, special conditions and requirements applicable to nuclear plants and special requirements applicable to the New York City metropolitan area.

Locational Based Marginal Pricing (“LBMP”): The price of Energy at each location in the NYS Transmission System as calculated pursuant to Section 17 Attachment B of this Services Tariff.

Locational Export Capacity: The MW of a Generator electrically located in an Import Constrained Locality that (a) has Capacity Resource Interconnection Service, pursuant to the applicable provisions of Attachments X, S, Z, or HH to the ISO OATT, and (b) that meets the eligibility requirements set forth in Section 5.9.2.2 of the Services Tariff.

Locational Minimum Installed Capacity Requirement: The portion of the NYCA Minimum Installed Capacity Requirement provided by Capacity Resources that must be electrically located within a Locality (including those combined with a Unforced Capacity Deliverability Right except for rights returned in an annual election to the ISO in accordance with ISO Procedures) in order to ensure that sufficient Energy and Capacity are available in that Locality and that appropriate reliability criteria are met.

Locational Minimum Unforced Capacity Requirement: The Unforced Capacity equivalent of the Locational Minimum Installed Capacity Requirement.

Long Island (“L.I.”): An electrical area comprised of Load Zone K, as identified in the ISO Procedures.

Lost Opportunity Cost: The foregone profit associated with the provision of Ancillary Services, which is equal to the product of: (1) the difference between (a) the Energy that a Generator or Aggregation could have sold at the specific LBMP and (b) the Energy sold as a result of reducing the Generator or Aggregation’s output to provide an Ancillary Service under the directions of the ISO; and (2) the LBMP existing at the time the Generator or Aggregation was instructed to provide the Ancillary Service, less the Generator or Aggregation’s Energy bid for the same MW segment.

Lower Operating Limit: For an Energy Storage Resource, a Hybrid Storage Resource or Aggregation containing Energy Storage Resources, the maximum amount of megawatts the Resource can consume from the grid, if it is bidding to withdraw Energy, or the minimum amount of MW the Resource can supply to the grid if it is not bidding to withdraw Energy. The Lower Operating Limit of an ISO-Managed Energy Storage Resource that is not bidding to withdraw Energy shall not be set to less than 0 MW. Bids for Energy Storage Resources with Self-Managed Energy Levels, Aggregations consisting entirely of Energy Storage Resources, and DER Aggregations may include a Lower Operating Limit that is greater than 0 MW when the Resource or Aggregation submits a self-committed Bid to inject Energy. The Lower Operating Limit of a Hybrid Storage Resource shall not be set to greater than 0 MW.

Lower Storage Limit: The minimum amount of Energy an Energy Storage Resource or Aggregation comprised entirely of Energy Storage Resources is physically capable of storing.

LSE Unforced Capacity Obligation: The amount of Unforced Capacity that each NYCA LSE must obtain for an Obligation Procurement Period as determined by the ICAP Demand Curve for the NYCA, the G-J Locality, New York City Locality, and/or the Long Island Locality, as applicable, for each ICAP Spot Market Auction. The amount includes, at a minimum, each LSE’s share of the NYCA Minimum Unforced Capacity Requirement and the Locational Minimum Unforced Capacity Requirement, as applicable.

2.14 Definitions - N

Native Load Customers: The wholesale and retail power customers of the Transmission Owners on whose behalf the Transmission Owners, by statute, franchise, regulatory requirement, or contract, have undertaken an obligation to construct and operate the Transmission Owners' systems to meet the reliable electric needs of such customers.

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

NCZ Study Capability Period: The Summer Capability Period that begins five years from May 1 in a calendar year including an NCZ Study Start Date.

NCZ Study Start Date: September 1 or the next business day thereafter in the calendar year prior to an ICAP Demand Curve Reset Filing Year.

Neptune Scheduled Line: A transmission facility that interconnects the NYCA to the PJM Interconnection LLC Control Area at Levittown, Town of Hempstead, New York and terminates in Sayerville, New Jersey.

NERC: The North American Electric Reliability Council or, as applicable, the North American Electric Reliability Corporation.

Net Auction Revenue: As defined in the ISO OATT.

Net Average Coincident Load (“Net ACL”): The effective Average Coincident Load calculated and used by the ISO for a Special Case Resource during a specific month in which a SCR Change of Status was reported for the resource or, beginning with the Summer 2014 Capability Period, an Incremental Average Coincident Load was reported for the resource.

Net Benefits Test: The monthly calculations performed by the ISO in accordance with Section 4.5.7.1 of the ISO Services Tariff and ISO Procedures to determine the Monthly Net Benefit Threshold, the price at which the Demand Reductions meet the test required by Commission Order 745.

Net Congestion Rent: As defined in the ISO OATT.

Net Installed Capacity (“Net-ICAP”): The amount of Installed Capacity that a BTM:NG Resource has demonstrated (in accordance with ISO Procedures) it is capable of supplying in accordance with Section 5.12.6.1 of this Tariff, used to determine its Net Unforced Capacity.

Net Unforced Capacity (“Net-UCAP”): The amount of Unforced Capacity a BTM:NG Resource can offer in the ISO’s Installed Capacity market.

Network Integration Transmission Service: The Transmission Service provided under Part 4 of the ISO OATT.

New Capacity Zone (“NCZ”): A single Load Zone or group of Load Zones that is proposed as a new Locality, and for which the ISO shall establish a Demand Curve.

New York City: The electrical area comprised of Load Zone J, as identified in the ISO Procedures.

New York Control Area (“NYCA”): The Control Area that is under the control of the ISO which includes transmission facilities listed in the ISO/TO Agreement Appendices A-1 and A-2, as amended from time-to-time, and generation located outside the NYS Power System that is subject to protocols (e.g., telemetry signal biasing) which allow the ISO and other Control Area operator(s) to treat some or all of that generation as though it were part of the NYS Power System.

New York Power Pool (“NYPP”): An organization established by agreement (the “New York Power Pool Agreement”) made as of July 21, 1966, and amended as of July 16, 1991, by and among Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., Long Island Lighting Company, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation, Orange and Rockland Utilities, Inc., Rochester Gas and Electric Corporation, and the Power Authority of the State of New York. LIPA became a Member of the NYPP on May 28, 1998 as a result of the acquisition of the Long Island Lighting Company by the Long Island Power Authority.

New York State Bulk Power Transmission Facility: This term shall have the meaning given in Attachment Y to the OATT.

New York State Power System (“NYS Power System”): All facilities of the NYS Transmission System, and all those Generators and Aggregations located within the NYCA or outside the NYCA, some of which may from time-to-time be subject to operational control by the ISO.

New York State Reliability Council (“NYSRC”): An organization established by agreement among the Member Systems to promote and maintain the reliability of the NYS Power System.

New York State Reliability Council Agreement (“NYSRC Agreement”): The agreement which established the NYSRC.

New York State Transmission System (“NYS Transmission System”): The entire New York State electric transmission system, which includes: (1) the Transmission Facilities Under ISO Operational Control; (2) the Transmission Facilities Requiring ISO Notification; and (3) all remaining transmission facilities within the NYCA.

Non-Competitive Proxy Generator Bus: A Proxy Generator Bus for an area outside of the New York Control Area that has been identified by the ISO as characterized by non-competitive Import or Export prices, and that has been approved by the Commission for designation as a

Non-Competitive Proxy Generator Bus. Non-Competitive Proxy Generator Buses are identified in Section 4.4.4 of the Services Tariff., as set forth in Section 4.4.2.2 of the MST

Non-Firm-Point-To-Point Transmission Service: Point-To-Point Transmission Service for which a Transmission Customer is not willing to pay Congestion. Such service is not available in the markets that the NYISO administers.

Non-Investment Grade Customer: A Customer that does not meet the criteria necessary to be an Investment Grade Customer, as set forth in Section 26.3 of Attachment K to this Services Tariff.

Non-Utility Generator ("NUG," "Independent Power Producer" or "IPP"): Any entity that owns or operates an electric generating facility that is not included in an electric utility's rate base. This term includes, but is not limited to, cogenerators and small power producers and all other non-utility electricity producers, such as exempt wholesale Generators that sell electricity.

Normal State: The condition that the NYS Power System is in when the Transmission Facilities Under ISO Operational Control are operated within the parameters listed for Normal State in the Reliability Rules. These parameters include, but are not limited to, thermal, voltage, stability, frequency, operating reserve and Pool Control Error limitations.

Normal Upper Operating Limit (UOL_N): The upper operating limit that a Generator or Aggregation, except for the Generator of a BTM:NG Resource, indicates it expects to be able to reach, or the upper operating limit a BTM:NG Resource indicates it expects to be able to inject into the grid after serving its Host Load and subject to its Injection Limit, during normal conditions. Each Resource will specify its UOL_N in its Bids which shall be reduced when the Resource requests that the ISO derate its Capacity or the ISO derates the Resource's Capacity. A Normal Upper Operating Limit may be submitted as a function depending on one or more variables, such as temperature or pondage levels, in which case the Normal Upper Operating Limit applicable at any time shall be determined by reference to that schedule. Self-committed Bids for Energy Storage Resources with Self-Managed Energy Levels, Aggregations consisting entirely of Energy Storage Resources and withdrawal-eligible DER Aggregations may include a negative UOL_N when the Resource or Aggregation bids to withdraw Energy from the grid. The UOL_N for ISO-Managed Energy Storage Resources or a Hybrid Storage Resource shall not be lower than 0 MW.

Northport-Norwalk Scheduled Line: A transmission facility that originates at the Northport substation in New York and interconnects the NYCA to the ISO New England Control Area at the Norwalk Harbor substation in Connecticut.

Notice of Intent to Return: The notice a Supplier with a Generator that is in a Mothball Outage or ICAP Ineligible Forced Outage provides to the ISO, pursuant to ISO Procedures, that gives the date by which it intends to return to the Energy market, which proposed return date shall be no later than the expiration date of the Generator's Mothball Outage or ICAP Ineligible Forced Outage.

NPCC: The Northeast Power Coordinating Council.

NRC: The Nuclear Regulatory Commission or any successor thereto.

NYCA Installed Reserve Margin: The ratio of the amount of additional Installed Capacity required by the NYSRC in order for the NYCA to meet NPCC reliability criteria to the forecasted NYCA upcoming Capability Year peak Load, expressed as a decimal.

NYCA Minimum Installed Capacity Requirement: The requirement established for each Capability Year by multiplying the NYCA peak Load forecasted by the ISO by the quantity one plus the NYCA Installed Reserve Margin.

NYCA Minimum Unforced Capacity Requirement: The Unforced Capacity equivalent of the NYCA Minimum Installed Capacity Requirement.

NYCA Peak Load Forecast: The NYISO calculation of the peak hourly demand condition for the design day occurring on a non-holiday weekday in July or August for the upcoming Capability Year which is determined in accordance with Sections 5.10 and 5.11 of the Services Tariff and is based upon the weather-adjusted Load for the hour during a non-holiday weekday in July or August in which actual Load in the NYCA was highest.

NYPA: The Power Authority of the State of New York.

NYPA Tax-Exempt Bonds: Obligations of the New York Power Authority, the interest on which is not included in gross income under the Internal Revenue Code.

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 provide Energy and that meets all applicable requirements of the ISO, NERC, NPCC and New York State Reliability Council. The ISO will administer Operating Reserves markets, in the manner described in 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 Aggregations that (i) meet the eligibility criteria set forth in Rate Schedule 4 of this ISO Services Tariff, (ii) are already synchronized to the NYS Power System, and (iii) 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. Aggregations containing at least one Distributed Energy Resource that individually qualifies to provide Spinning Reserves may elect to provide Spinning Reserve based on the combined capabilities of the participating Distributed Energy Resources that are eligible to provide Spinning Reserves. Spinning Reserves may not be provided by 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 where at least one Demand Side Resource facilitates its Demand Reduction using a Local Generator (unless the Local Generator(s) use inverter-based energy storage technology);

(2) 10-Minute Non-Synchronized Reserve: Operating Reserves provided by Generators, Aggregations, or Behind-the-Meter Net Generation Resources that are comprised of one or more generating units that are dispatched as a single aggregate unit, 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. Aggregations containing at least one Distributed Energy Resource that individually qualifies to provide 10-Minute Non-Synchronized Reserve may elect to provide 10-Minute Non-Synchronized Reserve based on the combined capabilities of the participating Distributed Energy Resources that are eligible to provide Spinning Reserves or 10-Minute Non-Synchronized Reserves; and

(3) 30-Minute Reserve: Synchronized Operating Reserves provided by (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, or (ii) Aggregations containing at least one Distributed Energy Resource that individually qualifies to provide 30-Minute Synchronized Operating Reserves; or non-synchronized Operating Reserves provided by (i) Generators, (ii) Aggregations, or (iii) Behind-the-Meter Net Generation Resources that are comprised of more than one generating units and dispatched as a single aggregate unit 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. Aggregations containing at least one Distributed Energy Resource that individually qualifies to provide 30-Minute Reserve may elect to provide 30-Minute Reserve based on the combined capabilities of the participating Distributed Energy Resources that are eligible to provide Spinning Reserves, 10-Minute Non-Synchronized Reserves or 30-Minute Reserves.

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 Reserve Limit: The capability, in MW, of a Hybrid Storage Resource or Aggregation to produce Energy for at least one hour if its Operating Reserve schedule is converted to Energy. The capability of a Hybrid Storage Resource to provide Operating Reserves shall be based on the capability of its Energy Storage Resource. The capability of an Aggregation to provide Operating Reserves shall be based on the capabilities of its Distributed Energy Resources. An Aggregation containing at least one Distributed Energy Resource that is capable of providing Operating Reserves will be subject to an Operating Reserve Limit, except for an Aggregation comprised entirely of Energy Storage Resources, which will instead follow the rules that apply to Energy Storage Resources. An Aggregation that is subject to an Operating Reserve Limit is referred to as an “Operating Reserves-eligible Aggregation.”

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 (See 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.

4.2 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. 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 scheduling 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 ISO-Committed Flexible or Fixed 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 scheduling 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).

A Supplier's Day-Ahead Market Self-Committed Flexible Bid for a DER Aggregation may include Energy withdrawals if the DER Aggregation includes at least one Withdrawal-Eligible Generator. A Supplier's hourly Day-Ahead Bids for a DER Aggregation to withdraw Energy and to supply Energy shall be submitted as a single, continuous bid curve representing the Capacity, in MW, that is being made available for each hour of the Dispatch Day. When the Energy Bid for a DER Aggregation includes both Energy supply and Energy withdrawal by a Withdrawal-Eligible Generator that is a component of the Aggregation, each point of the DER Aggregation's Bid curve shall reflect the net offer, such that any Energy withdrawals reduce the Energy the DER Aggregation is capable of supplying.

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 schedules it issues to CSR Generators.

A Supplier's Day-Ahead Bids for a Hybrid 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 scheduling in the Day-Ahead Market for each hour of the Dispatch Day. A Hybrid Storage Resource may not submit a Lower Operating Limit that exceeds zero MW, or an Upper Operating Limit that is less than zero MW.

Self-Managed Energy Storage Resources, Aggregations that are made up entirely of Energy Storage Resources and DER Aggregations may submit a Self-Committed Fixed or Flexible Bid to inject Energy that includes a Lower Operating Limit that is equal to or greater than zero MW. Self-Managed Energy Storage Resources, Aggregations that are made up entirely of Energy Storage Resources and withdrawal-eligible DER Aggregations may submit a Self-Committed Fixed or Flexible Bid to withdraw Energy that includes a Normal Upper

Operating Limit that is equal to or less than zero MW. Otherwise, Energy Storage Resources and Aggregations may not submit Bids that include a Lower Operating Limit that exceeds zero MW, or an Upper Operating Limit that is less than zero MW.

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 Hybrid Storage Resource or Operating Reserves-eligible Aggregation must submit an Operating Reserve Limit with each of its hourly Bids. A Behind-the-Meter Net Generation Resource that is comprised of more than one generating unit, or an Aggregation containing at least one generating unit (unless all of the generating unit(s) use inverter-based energy storage technology) that is dispatched as a single aggregate unit at a single PTID is not qualified to provide Regulation Service or Spinning Reserves. The Aggregator of an Operating Reserves-eligible Aggregation may elect to have the Aggregation provide any Operating Reserve product that at least one DER participating in the Aggregation is eligible to provide (Spinning Reserve, 10-Minute Non-Synchronized Reserve, or 30-Minute Reserve) for a given duration of enrollment. The quantity of Operating Reserves the Aggregation is able to provide shall be based on the combined capabilities of the participating DER that are eligible to provide the elected Operating Reserves product. An Aggregation that elects to provide Spinning

Reserve or 10-Minute Non-Synchronized Reserve may be awarded reserves by the ISO to fulfill the 30-Minute Reserve Requirement. The Aggregator may change its Operating Reserves product election on a monthly basis by submitting a change to the ISO in advance, which is subject to ISO review. A Supplier may resubmit a complete Day-Ahead Bid, provided that the new Bid is timely.

Suppliers 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 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. Resources that participate as CSR shall not submit Day-Ahead Market Bids that would self-commit either of the Generators, or both of the Generators together, to inject or to withdraw a quantity of Energy that exceeds an applicable CSR Scheduling Limit. An Energy Storage Resource that, together with a Generator that submits a Minimum Generation Bid or is a Fixed Block Unit, participates as Co-located Storage Resources shall not submit Day-Ahead Market Bids that would self-commit the Energy Storage Resource to inject Energy such that the Generator's Minimum Generation (or full output for a Fixed Block Unit), plus the Energy Storage Resource's self schedule, exceeds the CSR injection Scheduling Limit.

When a Generator that submits a Minimum Generation Bid or that is a Fixed Block Unit participates as a Co-located Storage Resource, the ISO will treat the Generator as operating at, at least, its Minimum Generation Level (or full output for a Fixed Block Unit) for the purpose of scheduling the Energy Storage Resource whenever the Generator is scheduled, including during start-up and shut-down periods.

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, and Aggregations containing at least one Withdrawal-Eligible Generator, shall also specify the Generator's Lower Operating Limit for each hour.

Bids from Suppliers for Generators and Aggregations 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 or Aggregation's Operating Capacity per minute. All Bids from Suppliers for Generators and Aggregations 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 or Aggregation.

4.2.1.3.4 Additional Parameters for Energy Storage Resources and Aggregations Comprised only of 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.

The rules in this section 4.2.1.3.4 shall also apply to Aggregations comprised entirely of Energy Storage Resources.

4.2.1.3.5 Additional Parameters for Hybrid Storage Resources and Operating Reserves-eligible Aggregations

In addition to the parameters that Suppliers submit for Generators, Hybrid Storage Resources and Operating Reserves-eligible Aggregations must also submit an Operating Reserve Limit for each hour of the Day-Ahead Market to indicate the Energy that the Hybrid Storage Resource or Operating Reserves-eligible Aggregation reasonably expects it will be able to provide for at least one hour if its Operating Reserve schedule is converted to Energy.

4.2.1.4 Offers to Supply Energy from Self-Committed Fixed Generators and Aggregations

Self-Committed Fixed Generators and Aggregations shall provide the ISO with a schedule of their expected Energy output and withdrawals (when applicable) for each hour. Self-Committed Fixed Generators and Aggregations are responsible for ensuring that any hourly changes in output are consistent with their response rates. Self-Committed Fixed Generators and Aggregations 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.

A Supplier may submit a Day-Ahead Market Self-Committed Fixed Bid for a DER Aggregation to withdraw Energy if the DER Aggregation includes at least one Withdrawal-Eligible Generator. When a Self-Committed Fixed Bid for a DER Aggregation reflects both Energy supply and Energy withdrawals by a Withdrawal-Eligible Generator that is a component of the Aggregation, the DER Aggregation's Bid shall reflect the net offer, such that any Energy withdrawals reduce the Energy the DER Aggregation is capable of supplying.

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). A Generator can be the Point of Injection for a Bilateral Transaction. A Withdrawal-Eligible Generator can be the Point of Injection or the Point of Withdrawal for a Bilateral Transaction, but it cannot be both the Point of Injection and the Point of Withdrawal for the same Bilateral Transaction. An Aggregation containing one or more Withdrawal-Eligible Generators can be the Point of Injection or the Point of Withdrawal for a Bilateral Transaction, but it cannot be both the Point of Injection and the Point of Withdrawal for the same Bilateral Transaction. An Aggregation containing one or more Demand Side Resources shall not be the Point of Injection or 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.

4.2.2 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 Energy 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 or Withdrawal-Eligible Generators as their POWs.

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 Aggregations to provide for the safe and reliable operation of the NYS Power System. SCUC will treat Behind-the-Meter Net Generation Resources, Hybrid Storage Resources, Energy Storage Resources, and Aggregations as already being committed and available to be scheduled. SCUC will account for the Operating Reserve Limit a Hybrid Storage Resource or Operating Reserves-eligible Aggregation submits in determining its schedule. 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 or Withdrawal-Eligible Generators 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 or Withdrawal-Eligible Generators as their POWs; (iv) price Bids and operating Constraints submitted for Generators or for Aggregations; (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 or Withdrawal-Eligible Generators as their POWs.

In the development of its SCUC schedule, the ISO may commit and de-commit Generators and Aggregations, 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 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 will select the least cost mix of Ancillary Services and Energy from Suppliers, 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 and/or Aggregations 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. A Transmission Owner that wishes to request the availability of a Hybrid Storage Resource or Aggregation to meet changed or local system conditions that may cause the Day-Ahead schedules for the Dispatch Day to be inadequate to ensure the reliability of its local system shall use the ISO's electronic portal to submit its request. The ISO will use SRE to fulfill a Transmission Owner's request for additional Resources.

All Generator and/or Aggregation 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 and/or Aggregation 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, Aggregations, or transmission facilities that may cause the Day-Ahead schedules to be inadequate to meet the Load or reliability requirements for the Dispatch Day.

Prior to the Capability Period beginning May 1, 2025, 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.

Beginning with the Capability Period beginning May 1, 2025, 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 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 Transmission Node as described in Attachment B. Each Supplier that bids a Generator or Aggregation 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 or Transmission Node; 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. 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, Hybrid Storage Resources, Energy Storage Resources, and Aggregations 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.

A Supplier's Real-Time Market Self-Committed Flexible Bid for a DER Aggregation may include Energy withdrawals if the DER Aggregation includes at least one Withdrawal-Eligible Generator. A Supplier's Real-Time Market Bids for a DER Aggregation to withdraw Energy and to supply Energy shall be submitted in a single, continuous bid curve representing the Capacity, in MW, that is being made available. When the Energy Bid for the DER Aggregation includes both Energy supply and Energy withdrawal by a Withdrawal-Eligible Generator that is a component of the Aggregation, each point of the DER Aggregation's Bid curve shall reflect the net offer, such that any Energy withdrawals reduce the Energy the DER Aggregation is capable of supplying.

A Supplier may submit a Real-Time Market Self-Committed Fixed Bid for a DER Aggregation to withdraw Energy if the DER Aggregation includes at least one Withdrawal-Eligible Generator. When a Self-Committed Fixed Bid for a DER Aggregation reflects both Energy supply and Energy withdrawals by a Withdrawal-Eligible Generator that is a component

of the Aggregation, the DER Aggregation's Bid shall reflect the net offer, such that any Energy withdrawals reduce the Energy the DER Aggregation is capable of supplying. However, if the Monthly Net Benefit Threshold price is less than the LBMP, Demand Side Resources shall not be permitted to net Energy withdrawals of Withdrawal-Eligible Generators in the DER Aggregation.

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.

In addition to the parameters that Suppliers submit for Generators, Hybrid Storage Resources and Operating Reserves-eligible Aggregations must also submit an Operating Reserve Limit with their Real-Time Market Bids to indicate the Energy that the Hybrid Storage Resource or Operating Reserves-eligible Aggregation reasonably expects it will be able to provide for at least one hour if its Operating Reserve schedule is converted to Energy. Hybrid Storage Resources and Operating Reserves-eligible Aggregations are required to update their Operating Reserve Limits to reflect changes to the Hybrid Storage Resource's or Operating Reserves-eligible Aggregation's ability to provide Operating Reserves in real-time. After the Real-Time Scheduling Window closes, Operating Reserve Limit changes must be submitted via the ISO's electronic portal. Updates to the Operating Reserves Limit submitted using the electronic portal will not be permitted to increase or to exceed the Operating Reserve Limit that the Hybrid Storage Resource or Operating Reserves-eligible Aggregation submitted with its Real-Time Bid for the relevant Real-Time Market hour. When a Hybrid Storage Resource or Operating Reserves-eligible Aggregation submits an updated Operating Reserve Limit via the ISO's electronic portal, it is required to concurrently submit an updated Upper Operating Limit if the

maximum output a Hybrid Storage Resource or Operating Reserves-eligible Aggregation is capable of achieving is also affected.

After the Real-Time Scheduling Window closes, Hybrid Storage Resources and Aggregations will also be required to submit changes to their Upper Operating Limits and Lower Operating Limit using the ISO's electronic portal if updates are necessary to reflect the Hybrid Storage Resource's or Aggregation's actual capabilities. The revised Upper Operating Limits and Lower Operating Limit that a Hybrid Storage Resource or Aggregation submits using the electronic portal may not exceed the Upper Operating Limits or be less than the Lower Operating Limit that the Hybrid Storage Resource or Aggregation submitted with its Bid for the relevant Real-Time Market hour. Submission of an updated Upper Operating Limit may also require the submission of a corresponding updated Operating Reserve Limit for the Hybrid Storage Resource or Operating Reserves-eligible Aggregation if the Operating Reserve Limit is also affected.

If the ISO issues an Out-of-Merit dispatch instruction to a Hybrid Storage Resource or Aggregation, the Hybrid Storage Resource or Aggregation will be expected to fully comply with the instruction. Requests to change the Upper Operating Limits, Lower Operating Limit or Operating Reserve Limit while a Hybrid Storage Resource or Aggregation is subject to an Out-of-Merit instruction must be approved by the ISO and should only be effectuated by the Hybrid Storage Resource or Aggregation after the ISO issues a change to the Out-of-Merit instruction.

It is the responsibility of the Hybrid Storage Resource or Operating Reserves-eligible Aggregation to submit Operating Reserve Limit, Upper Operating Limit and Lower Operating Limit updates in advance so that the ISO uses accurate information to determine a Hybrid Storage Resource's or Operating Reserves-eligible Aggregation's Energy, Regulation Service

and Operating Reserve schedules. The risk associated with any delay between the time an updated Operating Reserve Limit, Upper Operating Limits or Lower Operating Limit is submitted and its implementation in the ISO's market software is the responsibility of the Hybrid Storage Resource or Operating Reserves-eligible Aggregation.

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

Intermittent Power Resources and Aggregations that depend solely 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.

A Hybrid Storage Resource may not submit a Lower Operating Limit that exceeds zero MW, or an Upper Operating Limit that is less than zero MW. Self-Managed Energy Storage Resources, Aggregations that are made up entirely of Energy Storage Resources and DER Aggregations may submit a Self-Committed Fixed or Flexible Bid to inject Energy that includes a Lower Operating Limit that is equal to or greater than zero MW. Self-Managed Energy Storage Resources, Aggregations that are made up entirely of Energy Storage Resources and withdrawal-eligible DER Aggregations may submit a Self-Committed Fixed or Flexible Bid to withdraw Energy that includes a Normal Upper Operating Limit that is equal to or less than zero MW. Otherwise, Energy Storage Resources and Aggregations may not submit Bids that include

a Lower Operating Limit that exceeds zero MW, or an Upper Operating Limit that is less than zero MW.

Hybrid Storage Resources' and Aggregations' obligations to submit and update their Operating Reserve Limit, Upper Operating Limits and Lower Operating Limit are addressed in Section 4.4.1.2, above.

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 or Aggregations (except Aggregations comprised of only Intermittent Power Resources) that did not receive a Day-Ahead schedule for a given hour may offer their Generators or Aggregations, 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. A Supplier bidding on behalf of a Generator or Aggregation that received a Day-Ahead schedule for a given hour may not change the bidding mode for that Generator or Aggregation for the Real-Time Market for that hour provided, however, that Generators or Aggregations 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 or Aggregations 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. Resources that participate as CSR shall not submit Real-Time Market Bids that would self-commit either of the Generators, or both of the Generators together, to inject or to withdraw a quantity of Energy that exceeds an applicable CSR Scheduling Limit.

An Energy Storage Resource that, together with a Generator that submits a Minimum Generation Bid or is a Fixed Block Unit, participates as Co-located Storage Resources shall not submit Day-Ahead or Real-Time Market Bids that would self-commit the Energy Storage Resource to inject Energy such that the Generator's Minimum Generation (or full output for a Fixed Block Unit), plus the Energy Storage Resource's self schedule, exceeds the CSR injection Scheduling Limit.

When a Generator that submits a Minimum Generation Bid or that is a Fixed Block Unit participates as a Co-located Storage Resource, the ISO will treat the Generator as operating at its Minimum Generation Level (or full output for a Fixed Block Unit) for the purpose of scheduling the Energy Storage Resource whenever the Generator is scheduled, including during start-up and shut-down periods.

A Supplier's ISO-Committed Flexible or Fixed Real-Time Bids for an Energy Storage Resource, Hybrid Storage Resource, or Aggregation consisting entirely of Energy Storage Resources to withdraw Energy and to inject Energy shall be submitted as a single, continuous bid curve representing the Capacity, in MW, available for dispatch in the Real-Time Market. Generators and Aggregations with a real time physical operating problem 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. Hybrid Storage Resources and Aggregations are expected to utilize the ISO's electronic portal to notify the ISO, whenever possible. 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 Aggregations 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). RTC and RTD will consider a Hybrid Storage Resource's or Operating Reserves-eligible Aggregation's Operating Reserve Limit when determining the amount of Operating Reserves the Hybrid Storage Resource or Operating Reserves-eligible Aggregation may be scheduled to provide. The Aggregator of an Operating-Reserve eligible Aggregation may elect to have the Aggregation provide any Operating Reserve product that at least one DER participating in the Aggregation is eligible to provide (Spinning Reserve, 10-Minute Non-Synchronized Reserve, or 30-Minute Reserve) for a given duration of enrollment. The quantity of Operating Reserves the Aggregation is able to provide shall be based on the combined capabilities of the participating DER that are eligible to provide the elected Operating Reserve product. An Aggregation that elects to provide Spinning Reserve or 10-Minute Non-Synchronized Reserve may be awarded reserves by the ISO to fulfill the 30-Minute Reserve Requirement. The Aggregator may change its Operating Reserve product election on a monthly basis by submitting a change to the ISO in advance, which is subject to ISO review.

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.

RTC₁₅ 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 RTC₁₅ 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.*, RTC₃₀, RTC₄₅, and RTC₀₀ will begin executing at fifteen minutes before their designated posting times (for example, RTC₃₀ 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 Aggregations, 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. In each interval, Real-Time Dispatch will review the Beginning Energy Level of each Energy Storage Resource and of each Aggregation comprised only of Energy Storage Resources.

Real-Time Dispatch will attempt to prevent dispatching a Self-Managed Energy Storage Resource or Aggregation composed only of Energy Storage Resources in a manner that would be infeasible based on its Beginning Energy Level. Instead, Real-Time dispatch will consider an Energy Storage Resource's or Aggregation Composed of only Energy Storage Resources' Beginning Energy Level in developing a schedule for the binding interval. An Energy Storage

Resource's or an Aggregation composed only of Energy Storage Resources' 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, Transmission Node, 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 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.

Hybrid Storage Resources and Operating Reserves-eligible Aggregations are required to notify the NYISO of limitations affecting their ability to provide Operating Reserves by timely submitting and updating Operating Reserve Limits.

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, Hybrid Storage Resources, and Operating Reserves-eligible Aggregations. 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 and Aggregations 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 and Aggregations 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, Transmission Node, 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		Scheduling Frequencies		
					Requires CTS Bids	Permits CTS Bids	Hourly Scheduled	Variably Scheduled	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.

15.3 Rate Schedule 3 - Payments for Regulation Service

This Rate Schedule applies to Suppliers that provide Regulation Service to the ISO. The following Resources are not eligible to provide Regulation Service: (1) Behind-the-Meter Net Generation Resources that are comprised of more than one generating unit and that are dispatched as a single aggregate unit, (2) Aggregations that are comprised of one or more generating units (unless at least one of those generating units use inverter-based energy storage technology), and (3) Aggregations of Demand Side Resources where at least one Demand Side Resource facilitates its Demand Reduction by utilizing a Local Generator (unless at least one Local Generator uses inverter-based energy storage technology). The amount of Regulation Service an Aggregation is eligible to provide shall be based on the MW of Regulation Service capability each qualified and technically capable Distributed Energy Resource within the Aggregation can individually contribute to the Aggregation's composite capability, consistent with the obligations of Suppliers discussed below. A Distributed Energy Resource that is not qualified to provide Regulation Service may not contribute to an Aggregation's qualification or capability to provide Regulation Service.

Transmission Customers will purchase Regulation Service from the ISO under the ISO OATT.

15.3.1 Obligations of the ISO and Suppliers

15.3.1.1 The ISO shall:

- (a) Establish Regulation Service criteria and requirements in the ISO Procedures to ensure that Suppliers follow changes in Load consistent with the Reliability Rules;

- (b) Provide RTD Base Point Signals and AGC Base Point Signals to Suppliers providing Regulation Service to direct their output;
- (c) Establish criteria in the ISO Procedures that Suppliers must meet to qualify, or re-qualify, to supply Regulation Service;
- (d) Establish minimum metering requirements and telecommunication capability required for a Supplier to be able to respond to AGC Base Point Signals and RTD Base Point Signals sent by the ISO;
- (e) Select Suppliers to provide Regulation Service in the Day-Ahead Market and Real-Time Market and establish Regulation Service schedules, in MWs of Regulation Capacity, for each scheduled Regulation Supplier in the Day-Ahead and Real-Time Markets, as described in Section 15.3.2 of this Rate Schedule;
- (f) Pay Suppliers for providing Regulation Service as described in this Rate Schedule;
- (g) Monitor Suppliers' performance to ensure that they provide Regulation Service as required, as described in Section 15.3.3 of this Rate Schedule; and
- (h) Take into account the speed and accuracy of regulation resources in determining reserve requirements for Regulation Service.

15.3.1.2 Each Supplier shall:

- (a) Register with the ISO the Regulation Capacity its resources are qualified to bid in the Regulation Services market;
- (b) Provide the ISO with the Resource's Regulation Capacity Response Rate and the Resource's Regulation Movement Response Rate;

- (c) Offer only Resources that are; (i) ISO-Committed Flexible or Self-Committed Flexible, within the dispatchable portion of their operating range, and; (ii) able to respond to AGC Base Point Signals sent by the ISO pursuant to the ISO Procedures, to provide Regulation Service;
- (d) Not use, contract to provide, or otherwise commit Regulation Capacity that is selected by the ISO to provide Regulation Service to provide Energy or Operating Reserves to a Balancing Authority other than the ISO;
- (e) Pay any charges imposed under this Rate Schedule;
- (f) Ensure that all of its Resources that are selected to provide Regulation Service comply with Base Point Signals issued by the ISO at all times pursuant to the ISO Procedures; and ensure that all of its Resources that are selected to provide Regulation Service comply with all criteria and ISO Procedures that apply to providing Regulation Service.

15.3.2 Selection of Suppliers in the Day-Ahead Market and the Real-Time Market

- (a) The ISO shall select Suppliers in the Day-Ahead Market to provide Regulation Service for each hour in the following Dispatch Day and in the Real-Time Market to provide Regulation Service for each interval in the Dispatch Day, from those that have Bid to provide Regulation Service from Resources and that meet the qualification standards and criteria established in Section 15.3.1 of this Rate Schedule and in the ISO Procedures.
- (b) In order to schedule Suppliers in the Day-Ahead Market to provide Regulation Service for each hour in the following Dispatch Day, the ISO shall use, as each Supplier's Regulation Service Bid price, the sum of: a) the Supplier's Day-Ahead

Regulation Capacity Bid Price and b) the product of the Supplier's Day-Ahead Regulation Movement Bid Price and the applicable Regulation Movement Multiplier.

- (c) In order to schedule Suppliers in the Real-Time Market to provide Regulation Service for each interval in the Dispatch Day the ISO shall use, as each Supplier's Regulation Service Bid price, the sum of: a) the Supplier's Real-Time Regulation Capacity Bid Price and b) the product of the Supplier's Real-Time Regulation Movement Bid Price and the applicable Regulation Movement Multiplier.
- (d) The ISO shall establish separate Regulation Capacity Market Prices in the Day-Ahead Market and the Real-Time Market under Sections 15.3.4, 15.3.5 and 15.3.7 of this Rate Schedule and shall establish a Real-Time Regulation Movement Market Price under Section 15.3.5.1 of this Rate Schedule. The ISO shall also compute Regulation Revenue Adjustment Payments and Regulation Revenue Adjustment Charges under Section 15.3.6 of this Rate Schedule.

15.3.2.1 Bidding Process

- (a) A Supplier may submit a Bid in the Day- Ahead Market or the Real-Time Market to provide Regulation Service from eligible Resources, provided, however, that Bids submitted by Suppliers that are attempting to re-qualify to provide Regulation Service, after being disqualified pursuant to Section 15.3.3 of this Rate Schedule 3, may be limited by the ISO pursuant to ISO Procedures.
- (b) Bids rejected by the ISO may be modified and resubmitted by the Supplier to the ISO in accordance with the terms of the ISO Tariff.

- (c) Each Bid shall contain the following information: (i) the maximum amount of capability (in MW) that the Resource is willing to provide as Regulation Capacity; (ii) the Supplier's Bid Price (in \$/MW) for Regulation Capacity; and (iii) the Suppliers Bid Price (in \$/MW) for Regulation Movement.
- (d) Regulation Service Offers from Limited Energy Storage Resources: The ISO may reduce the real-time Regulation Capacity offer (in MWs) from a Limited Energy Storage Resource or an Aggregation of Limited Energy Storage Resources to account for the Energy storage capacity of such Resource.
- (e) Regulation Service Offers from Energy Storage Resources: The ISO may reduce the real-time Regulation Capacity (in MW) from an Energy Storage Resource or an Aggregation of Limited Energy Storage Resources to account for the Energy Level of such Resource.

15.3.3 Monitoring Regulation Service Performance and Performance Related Payment Adjustments

- (a) The ISO shall establish (i) Resource performance measurement criteria; (ii) procedures to disqualify Suppliers whose Resources consistently fail to meet those criteria; and (iii) procedures to re-qualify disqualified Suppliers, which may include a requirement to first demonstrate acceptable performance for a time.
- (b) The ISO shall establish and implement a Performance Tracking System to monitor the performance of Suppliers that provide Regulation Service. The ISO shall develop performance indices, which may vary with Control Performance, as part of the ISO Procedures. The ISO shall use the values provided by the Performance Tracking System to adjust settlements for real-time Regulation Movement pursuant to Section 15.3.5.4.1 and to compute a performance charge to

apply to real-time Regulation Service providers pursuant to Section 15.3.5.4.2 of this Rate Schedule.

- (c) Resources that consistently fail to perform adequately may be disqualified by the ISO, pursuant to ISO Procedures.

15.3.4 Regulation Service Settlements - Day-Ahead Market

15.3.4.1 Calculation of Day-Ahead Market Prices

The ISO shall calculate a Day-Ahead Regulation Capacity Market Price for each hour of the following day. The Day-Ahead Regulation Capacity Market Price for each hour shall equal the Day-Ahead Shadow Price of the ISO's Regulation Service constraint for that hour, which shall be established under the ISO Procedures, minus the product of i) the Day-Ahead Regulation Movement Bid Price of the marginal Resource selected to provide Regulation Service; and ii) the applicable Regulation Movement Multiplier. Day-Ahead Shadow Prices will be calculated by the ISO's SCUC. Each hourly Day-Ahead Shadow Price shall equal the marginal Bid cost of scheduling Resources to provide additional Regulation Service in that hour, including any impact on the Bid Production Cost of procuring Energy or Operating Reserves that would result from procuring an increment of Regulation Service in that hour, as calculated during the fifth SCUC pass described in Section 17.1.3 of Attachment B to this ISO Services Tariff. As a result, the Shadow Price shall include the Day-Ahead Regulation Service Bids of the marginal Resource selected to provide Regulation Service, plus any margins on the sale (or purchase by a Withdrawal-Eligible Generator) of Energy or the sale of Operating Reserves in the Day-Ahead Market that the Resource would forego if scheduling it to provide additional Regulation Service would lead to it being scheduled to provide (or for a Withdrawal-Eligible Generator to withdraw) less Energy or to provide less Operating Reserves (or the applicable price on the

Regulation Service Demand Curve during shortage conditions). Shadow Prices consistent with the Regulation Service Demand Curves described in Section 15.3.7 of this Rate Schedule will ensure that Regulation Service is not scheduled by SCUC at a cost greater than the Regulation Service Demand Curve.

Each Supplier that is scheduled Day-Ahead to provide Regulation Service shall be paid the Day-Ahead Regulation Capacity Market Price in each hour, multiplied by the amount of Regulation Capacity that it is scheduled Day-Ahead to provide in that hour.

15.3.4.2 Other Day-Ahead Payments

A Supplier that bids on behalf of a Generator or Aggregation that provides Regulation Service 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.

No payments shall be made to any Supplier providing Regulation Service in excess of the amount of Regulation Service scheduled by the ISO in the Day-Ahead Market, except to the extent that a Supplier is directed to provide the excess amount by the ISO.

15.3.5 Regulation Service Settlements - Real-Time Market

15.3.5.1 Calculation of Real-Time Market Prices

The ISO shall calculate a Real-Time Regulation Capacity Market Price and a Real-Time Regulation Movement Market Price for every RTD interval, except as noted in Section 15.3.8 of this Rate Schedule. The Real-Time Regulation Capacity Market Price for each interval shall equal the real-time Shadow Price for the ISO's Regulation Service constraint for that RTD interval, which shall be established under the ISO Procedures, minus the product of: i) the real-time Regulation Movement Bid of the marginal Resource selected to provide Real-Time Regulation Service; and ii) the applicable Regulation Movement Multiplier. Real-time Shadow

Prices will be calculated by the ISO's RTD. Each Real-Time Shadow Price in each RTD interval shall equal the marginal Bid cost of scheduling Resources to provide additional Regulation Service in that interval, including any impact on the Bid Production Cost of procuring Energy or Operating Reserves that would result from procuring an increment of Regulation Service in that interval. As a result, the Shadow Price shall include the Real-Time Regulation Service Bids of the marginal Resource selected to provide Regulation Service, plus any margins on the sale (or for Withdrawal-Eligible Generators, the purchase) of Energy or the sale of Operating Reserves in the Real-Time Market that Resource would forego if scheduling it to provide additional Regulation Service would lead to it being scheduled to provide or withdraw less Energy or to provide less Operating Reserves (or the applicable price on the Regulation Service Demand Curve during shortage conditions). Shadow Prices consistent with the Regulation Service Demand Curves described in Section 15.3.7 of this Rate Schedule will ensure that Regulation Service is not scheduled at a cost greater than the Demand Curve indicates.

During any period when the ISO sets Resources' Regulation Service Schedules to zero, pursuant to Section 15.3.8 of this Rate Schedule, the Real-Time Regulation Capacity Market Price and the Real-Time Regulation Movement Market Price shall automatically be set to zero, which shall be the price used for real-time balancing and settlement purposes.

The ISO shall calculate a Real-Time Regulation Movement Market Price for every RTD interval. The Real-Time Regulation Movement Market Price shall be the Regulation Movement Bid of the marginal Resource selected to provide Regulation Service in that interval.

15.3.5.2 Real-Time Regulation Capacity Balancing Payments, Regulation Movement Payments and Performance Charges

Any deviation from a Supplier's Day-Ahead schedule to provide Regulation Service shall be settled pursuant to the following rules. In addition, Suppliers scheduled to provide Regulation Service in real-time shall be settled pursuant to the following rules.

- (a) When the Supplier's real-time Regulation Capacity schedule is less than its Day-Ahead Regulation Capacity schedule, the Supplier shall pay a charge for the imbalance equal to the product of: (i) the Real-Time Regulation Capacity Market Price; and (ii) the difference between the Supplier's Day-Ahead Regulation Capacity schedule and its real-time Regulation Capacity schedule.
- (b) When the Supplier's real-time Regulation Capacity schedule is greater than its Day-Ahead Regulation Capacity schedule, the ISO shall pay the Supplier an amount to compensate it for the imbalance equal to the product of: (i) the Real-Time Regulation Capacity Market Price; and (ii) the difference between the Supplier's real-time Regulation Capacity schedule and its Day-Ahead Regulation Capacity schedule.
- (c) The ISO shall pay Suppliers with real-time Regulation Capacity schedules a real-time payment for Regulation Movement provided in each interval. The payment amount shall equal the product of: (a) the Real-Time Regulation Movement Market Price in that interval; (b) the Regulation Movement instructed during the interval, and (c) the performance factor calculated for that Regulation Service provider in that interval pursuant to Section 15.3.5.4.1.
- (d) The ISO shall assess a performance charge, pursuant to Section 15.3.5.4.2 to all Suppliers of Regulation Service with real-time Regulation Service schedules.

- (e) No payments shall be made to any Supplier providing Regulation Service in excess of the amount of Regulation Service scheduled by the ISO in the Real Time Market, except to the extent that a Supplier is directed to provide the excess amount by the ISO.

15.3.5.3 Other Real-Time Regulation Service Payments

A Supplier that bids on behalf of a Regulation Service provider may be eligible for a real-time Bid Production Cost guarantee payment pursuant to Section 4.6.6 and Attachment C of this ISO Services Tariff.

A Supplier that bids on behalf of a Regulation Service provider 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.

15.3.5.4 Performance-Based Adjustment to Payments for Regulation Service Providers and Performance Based Charges

15.3.5.4.1 Performance-Based Adjustment to Payments for Regulation Service Suppliers

The amount paid to each Supplier for providing Regulation Movement in each RTD interval, pursuant to Section 15.3.5.2 shall be reduced to reflect the Supplier's performance using a performance factor developed pursuant to the following equation:

$$K_{PLi} = (PI_i - PSF)/(1 - PSF)$$

Where:

K_{PLi} = the performance factor derived from the Regulation Service Performance index for the Resource for interval i ;

PI_i = the performance index of the Resource for interval i , with a value between 0.0 and 1.0 inclusive, derived from each Supplier's Regulation Service

performance, as measured by the performance indices set forth in the ISO Procedures; and

PSF = the payment scaling factor, established pursuant to ISO Procedures. The PSF shall be set between 0 and the minimum performance index required for payment for Regulation Service.

The PSF is established to reflect the extent of ISO compliance with the standards established by NERC, NPCC or Good Utility Practice for Control Performance and System Security. The PSF is set initially at zero. Should the ISO's compliance with these measures deteriorate, in a manner that can be improved if regulation performance improves, the PSF will be increased. Resources providing Regulation Service will be required to increase their performance index to obtain the same total Regulation Service payment as they received during periods of good ISO performance, as measured by these standards.

15.3.5.4.2 Performance-Based Charge to Suppliers of Regulation Service

In addition, each Supplier that is scheduled in real-time to provide Regulation Service shall be assessed a performance charge for interval *i* in accordance with the following formula.

$$\begin{aligned} \text{Performance Charge}_i &= \left(((1 - K_{PLi}) * RTRinccap_i * -1.1 * RTMPreg_i) \right. \\ &\quad \left. + \left(((1 - K_{PLi}) * (RTRcap_i - RTRinccap_i) * -1.1) * \text{Max}(DAMPreg, RTMPreg_i) \right) \right) * (S_i / 3600) \end{aligned}$$

DAMPreg_i = is the applicable Regulation Capacity Market Price (in \$/MW), in the Day-Ahead Market, as established by the ISO pursuant to Section 15.3.4.1 of this Rate Schedule for the hour that includes RTD interval *i*;

RTMPreg_i = is the applicable Regulation Capacity Market Price (in \$/MW), in the Real-Time Market as established by the ISO under Section 15.3.5.1 of this Rate Schedule in RTD interval *i*;

RTRcap_i = is the Regulation Capacity (in MW) offered by the Resource and selected by the ISO in the Real-Time Market in RTD interval *i*;

$RT Rinccap_i$ = is the incremental Regulation Capacity (in MW) offered by the Resource and selected by the ISO in the Real-Time Market in the RTD interval i which is in excess of Regulation Capacity offered and selected by the ISO in the Day-Ahead Market for the hour that includes interval i ;

S_i = is the number of seconds in interval i ; and

K_{PIi} = is the performance factor for the Resource for interval i as defined in Section 15.3.5.4.1.

15.3.6 Energy Settlement Rules for Suppliers Providing Regulation Service

15.3.6.1 Energy Settlements

- A. For any interval in which a Generator or Aggregation that is not a Limited Energy Storage Resource or an Aggregation of Limited Energy Storage Resources is providing Regulation Service, it shall receive a settlement payment for Energy consistent with a real-time Energy injection equal to the lower of the actual Energy it provides or its AGC Base Point Signal. Demand Side Resources providing Regulation Service shall not receive a settlement payment for Energy.
- B. Demand Reductions from Aggregations providing Regulation Service are only eligible for payment for Energy when the real-time LBMP, at the Aggregation's Transmission Node, meets or exceeds the Net Benefits Test Threshold calculated in accordance with Section 4.5.7 of the Services Tariff for the applicable period. When the Net Benefits Test Threshold is satisfied, such Aggregations shall receive an Energy payment for Demand Reductions equal to the lower of the Demand Reductions' contribution to the actual Energy provided or the Aggregation's AGC Base Point Signal.
- C. For any hour in which a Limited Energy Storage Resource or Aggregation of Limited Energy Storage Resources has injected or withdrawn Energy, pursuant to

an ISO schedule to do so, it shall receive a settlement payment (if the amount calculated below is positive) or charge (if the amount calculated below is negative) for Energy pursuant to the following formula:

$$\text{Energy Settlements}_h = \text{Net MWHR}_h * \text{LBMP}_h$$

Where:

Net MWHR_h = the amount of Energy injected by the Limited Energy Storage Resource or Aggregation of Limited Energy Storage Resources in hour h minus the amount of Energy withdrawn by that Limited Energy Storage Resource or Aggregation of Limited Energy Storage Resources in hour h

LBMP_h = the time-weighted average LBMP in hour h calculated for the location of that Limited Energy Storage Resource or Aggregation of Limited Energy Storage Resources

15.3.6.2 Additional Payments/Charges

For any interval in which a Supplier that is providing Regulation Service receives an AGC Base Point Signal that differs from its RTD Base Point Signal, it shall receive or pay a Regulation Revenue Adjustment Payment (“RRAP”) or Regulation Revenue Adjustment Charge (“RRAC”) calculated under the terms of this subsection, provided however no RRAP shall be payable and no RRAC shall be charged to a Limited Energy Storage Resource or Aggregation of Limited Energy Storage Resources.

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

For any interval in which a Supplier that is providing Regulation Service receives an AGC Base Point Signal that is higher than its RTD Base Point Signal, it shall receive or pay a RRAP or RRAC calculated under the terms of this subsection. If the Energy Bid Price of such a Supplier is higher than the LBMP at its location in that interval, the Supplier shall receive a RRAP. Conversely, for any interval in which such a Supplier’s Energy Bid Price is lower than

the LBMP at its location at that interval, the Supplier shall be assessed a RRAC. RRAPs and RRACs shall be calculated using the following formula:

$$Payment/Charge = \int_{RTD\ Base\ Point\ Signal}^{max(RTD\ BasePoint\ Signal, min(AGC\ BasePoint\ Signal, Actual\ Output))} [Bid - LBMP] * S/3600$$

Where:

S = the number of seconds in the RTD interval;

If the result of the calculation is positive then the Supplier shall receive a RRAP. If it is negative then the Supplier shall be subject to a RRAC. For purposes of applying this formula, whenever the Supplier's actual Bid exceeds the applicable LBMP the "Bid" term shall be set at a level equal to the lesser of the Supplier's actual Bid or its reference Bid plus \$100/MWh.

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

For any interval in which a Supplier that is providing Regulation Service receives an AGC Base Point Signal that is lower than its RTD Base Point Signal, it shall receive or pay a RRAP or RRAC calculated under the terms of this subsection. If the Energy Bid Price of such a Supplier is higher than the LBMP at its location in that interval, the Supplier shall be assessed a RRAC. Conversely, for any interval in which such a Supplier's Energy Bid Price is lower than the LBMP at its location in that interval, the Supplier shall receive a RRAP. RRAPs and RRACs shall be calculated using the following formula:

$$Payment/Charge = \int_{min(RTD\ BasePoint\ Signal, max(AGC\ BasePoint\ Signal, Actual\ Output))}^{RTD\ BasePoint\ Signal} -[Bid - LBMP] * S/3600$$

Where:

S = the number of seconds in the RTD interval;

If the result of the calculation is positive then the Supplier shall receive a RRAP. If it is negative then the Supplier shall be subject to a RRAC. For purposes of this formula, whenever the Supplier's actual Bid is lower than the applicable LBMP the "Bid" term shall be set at a level equal to the higher of the Supplier's actual Bid or its reference Bid minus \$100/MWh.

15.3.7 Regulation Service Demand Curve

The ISO shall establish a Regulation Service Demand Curve that will apply to both the Day-Ahead and real-time Regulation Capacity Market Price and settlements. The Regulation Capacity Market Prices calculated pursuant to Sections 15.3.4.1 and 15.3.5.1 of this Rate Schedule shall take account of the demand curve established in this Section so that Regulation Capacity is not scheduled by SCUC, RTC, or RTD at a cost higher than the demand curve indicates should be paid in the relevant market.

The ISO shall establish and post a target level of Regulation Service for each hour, which will be the number of MW of Regulation Capacity that the ISO would seek to maintain as its Regulation Service requirement in that hour. The ISO will then define a Regulation Service demand curve for that hour as follows:

For quantities of Regulation Capacity that are less than or equal to the target level of Regulation Service minus 80 MW, the price on the Regulation Service demand curve shall be \$775/MW.

For quantities of Regulation Capacity that are less than or equal to the target level of Regulation Service minus 25 MW but that exceed the target level of Regulation Service minus 80 MW, the price on the Regulation Service demand curve shall be \$525/MW.

For quantities of Regulation Capacity that are less than or equal to the target level of Regulation Service but that exceed the target level of Regulation Service minus 25 MW, the price on the Regulation Service demand curve shall be \$25/MW.

For all other quantities, the price on the Regulation Service demand curve shall be \$0/MW. However, the ISO shall not schedule more Regulation Service than the target level for the requirement for that hour.

In order to respond to operational or reliability problems that arise in real-time, the ISO may procure Regulation Capacity 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 Regulation Service Demand Curve the ISO, in consultation with its Advisor, shall conduct an initial review in accordance with the ISO Procedures. The scope of the review shall be upward or downward in order to optimize the

economic efficiency of any, or all, 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 15.3.7 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 Regulation Service Demand Curve.

The responsibilities of the Market Monitoring Unit that are addressed in the above section of Rate Schedule 3 to the Services Tariff are also addressed in Section 30.4.6.4.1 of Attachment O.

15.3.8 Temporary Suspension of Regulation Service Markets During Reserve Pickups and Maximum Generation

During any period in which the ISO has activated its RTD-CAM software and called for a "large event" or "small event" reserve or maximum generation pickup, as described in Article 4.4.4.1 of this ISO Services Tariff, the ISO will set all Regulation Service schedules to zero. The ISO will establish real-time Regulation Market Prices for Regulation Capacity and Regulation Movement of zero for settlement and balancing purposes. The ISO will restore real-time Regulation Service schedules as soon as possible after the end of the reserve or maximum generation pickup.

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. The following types of resources are only eligible to provide Spinning Reserve if all of the generating units use inverter-based energy storage technology and meet the criteria set forth in the ISO Procedures: (a) Aggregations comprised of one or more generating units, (b) Aggregations that include Demand Side Resource(s) where at least one Demand Side Resource facilitates its Demand Reduction by utilizing a Local Generator, and (c) 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) Aggregations comprised solely of generating units that are capable of increasing their supply level 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 and Aggregations that are comprised of more than one generating unit, that are ISO-Committed Flexible or Self-Committed Flexible and operating within the dispatchable portion of their operating range shall be eligible to supply synchronized 30-Minute Reserves. Aggregations that include/Demand Side Resource(s) 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, including Aggregations with a combination of Resources utilizing inverter-based energy storage technology and Demand Side Resources, 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) Aggregations comprised of one or more generating units that are capable

of increasing their output level 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 and Aggregations:

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.

A Hybrid Storage Resource or Operating Reserves-eligible Aggregation shall employ the Operating Reserve Limit functionality to limit the Operating Reserves it can be scheduled to provide based on the physical or operational capability of its participating Energy Storage Resource or comprising Distributed Energy Resources that are qualified to provide the applicable Operating Reserves product(s). The amount of Operating Reserves an Operating Reserves-eligible Aggregation is eligible to provide shall be based on the MW of Operating Reserves capability each qualified and technically capable Distributed Energy Resource within the Operating Reserves-eligible Aggregation can individually contribute to the Operating Reserves-eligible Aggregation's composite capability. A Distributed Energy Resource that is not qualified

to provide Operating Reserves may not contribute to an Operating Reserves-eligible Aggregation's qualification or capability to provide Operating Reserves.

Suppliers that are selected to provide Operating Reserve in the Day-Ahead Market may increase their Incremental Energy Bids respectively, for portions of their Resources that have been scheduled; provided however, that they are not otherwise prohibited from doing so pursuant to other provisions of the ISO's Tariffs. Withdrawal-Eligible Generators or Aggregations comprised of one or more Withdrawal-Eligible Generators that are scheduled to withdraw Energy, and that are selected to provide Operating Reserve in the Day-Ahead Market, may decrease their Bids to withdraw Energy for portions of their resources that have been scheduled through those processes; provided that they are not otherwise prohibited from doing so pursuant to other provisions of the ISO's Tariffs. Suppliers that are selected to provide Operating Reserve in the Day-Ahead Market may not reduce the UOL_N in their Real-Time Market Bids below the sum of their Day-Ahead Market schedules for Energy, Operating Reserve, and Regulation Service, except to the extent that they are directed to do so by the ISO. The ISO may reduce the real-time Operating Reserve schedule (in MW) from an Energy Storage Resource to account for the Energy Level of such Resource, as discussed in Section 4.4.2.1 of this ISO Services Tariff. Suppliers 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 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 or an Aggregation of Energy Storage Resources, the Resource's Energy schedule minus its Regulation Service schedule shall not be less than the Resource's Lower Operating Limit.

For an Energy Storage Resource, Hybrid Storage Resource or Aggregation of Energy Storage Resources that is withdrawing Energy, the sum of the Resource's or Aggregation'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 and any other participating Generator that is eligible to provide Regulation Service are scheduled to provide, and the amount of each Operating Reserves product the Energy Storage Resource and any other participating Generator that is eligible to provide Operating Reserves are scheduled to provide, shall account for the CSR injection Scheduling Limit consistent with ISO Procedures. The net amount of Energy that the CSR Generators are scheduled to withdraw, plus the amount of Regulation Service the Energy Storage Resource and any other participating Generator that is eligible to provide Regulation Service are scheduled to provide, shall account for the CSR withdrawal Scheduling Limit consistent with ISO Procedures.

The Operating Reserves a Hybrid Storage Resource or Operating Reserves-eligible Aggregation is scheduled to provide will be limited by an Operating Reserve Limit that is provided with the Resource's Availability Bid. Operating Reserve Limits must reflect expected or actual physical or operational, not economic, limitations.

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 or Energy 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, (a) the sum of the amount of Energy 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, and (b) the quantity of Operating Reserves a Hybrid Storage Resource or Operating Reserves-eligible Aggregation is scheduled to provide may be further limited by an Operating Reserve Limit that is considered by the NYISO's Real-Time Commitment or its Real-Time Dispatch (as appropriate).

For an Energy Storage Resource, Hybrid Storage Resource, or an Aggregation of Energy Storage Resources that is withdrawing Energy, the sum of the Resource's or Aggregation'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 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 and any

other participating Generator that is eligible to provide Regulation Service are scheduled to provide, and the amount of each Operating Reserves product the Energy Storage Resource and any other participating Generator that is eligible to provide Operating Reserves are scheduled to provide, shall account for the CSR injection Scheduling Limit consistent with ISO Procedures. The net amount of Energy that the CSR Generators are scheduled to withdraw, plus the amount of Regulation Service the Energy Storage Resource and any other participating Generator that is eligible to provide Regulation Service are scheduled to provide, shall account for the CSR withdrawal Scheduling Limit consistent with ISO Procedures.

Operating Reserve Limits must reflect expected or actual physical or operational, not economic, limitations, and must be updated consistent with Section 4.4.1.2 of the Services Tariff.

Suppliers will thus be selected on the basis of their response rates, their applicable upper operating limits, applicable Operating Reserve 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, 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, withdrawals, and Demand Reductions against its expected performance in real-time. When a Hybrid Storage Resource or Operating Reserves-eligible Aggregation is activated, its expected performance shall be measured against the MW that were activated and shall not consider any not-yet-implemented or subsequently submitted Operating Reserve Limit. The ISO may disqualify Suppliers that consistently fail to provide Energy, 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 Aggregation 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 and Aggregations that are selected to provide Operating Reserves Day-Ahead, but are directed to convert to Energy production or, for Withdrawal-Eligible Generators and Aggregations that include Withdrawal-Eligible Generator(s), 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) an Aggregation 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 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 \$40/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 \$40/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 \$40/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 655 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 (i) are less than or equal to the target level for that locational requirement minus 600 MW, but (ii) exceed the target level for that locational requirement minus 655 MW, the price on the total 30-Minute Reserves demand curve shall be \$625/MW. For quantities of Operating Reserves meeting the total 30-Minute Reserves requirement that (i) are less than or equal to the target level for that locational requirement minus 545 MW, but (ii) exceed the target level for that locational requirement minus 600 MW, the price on the total 30-Minute Reserves demand curve shall be \$500/MW. For quantities of Operating Reserves meeting the total 30-Minute Reserves requirement that (i) are less than or equal to the target level for that locational requirement minus 490 MW, but (ii) exceed the target level for that locational requirement minus 545 MW, the price on the total 30-Minute Reserves demand curve shall be \$375/MW. For quantities of Operating Reserves meeting the total 30-Minute Reserves requirement that (i) are less than or equal to the target level for that locational requirement minus 435 MW, but (ii) exceed the target level for that locational requirement minus 490 MW, the price on the total 30-Minute Reserves demand curve shall be \$300/MW. For quantities of Operating Reserves meeting the total 30-Minute Reserves requirement that (i) are less than or equal to the target level for that locational requirement minus 380 MW, but (ii) exceed the target level for that locational requirement minus 435 MW, the price on the total 30-Minute Reserves demand curve shall be \$225/MW. For quantities of Operating Reserves meeting the total 30-Minute Reserves requirement that (i) are

less than or equal to the target level for that locational requirement minus 325 MW, but (ii) exceed the target level for that locational requirement minus 380 MW, the price on the total 30-Minute Reserves demand curve shall be \$175/MW. For quantities of Operating Reserves meeting the total 30-Minute Reserves requirement that (i) are less than or equal to the target level for that locational requirement minus 200 MW, but (ii) exceed the target level for that locational requirement minus 325 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 (i) are less than or equal to the target level for that locational requirement, but (ii) exceed the target level for that locational requirement minus 200 MW, the price on the total 30-Minute Reserves demand curve shall be \$40/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 target level established for 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 655 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 (i) are less than or equal to the NYCA scarcity target level minus an amount equal to the sum of 600 MW and the Scarcity Reserve Requirement, but (ii) exceed the NYCA scarcity target level minus an amount equal to the sum of 655 MW and the Scarcity Reserve Requirement, the price on the total 30-Minute Reserves demand curve shall be \$625/MW. For quantities of Operating Reserves meeting the NYCA scarcity target level that (i) are less than or equal to the NYCA scarcity target, but (ii) exceed the NYCA scarcity target level minus an amount equal to the sum of 600 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 NYCA scarcity target level 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 an amount equal to the sum of 655 MW and the Scarcity Reserve Requirement(s),

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 (i) are less than or equal to the adjusted NYCA target level minus an amount equal to the sum of 600 MW and the Scarcity Reserve Requirement(s), but (ii) exceed the adjusted NYCA target level minus an amount equal to the sum of 655 MW and the Scarcity Reserve Requirement(s), the price on the total 30-Minute Reserves demand curve shall be \$625/MW. For quantities of Operating Reserves meeting the adjusted NYCA target level that (i) are less than or equal to the adjusted NYCA target level, but (ii) exceed the adjusted NYCA target level minus an amount equal to the sum of 600 MW and the Scarcity Reserve Requirement(s), 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 adjusted NYCA target level 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 \$40/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 (i) are less than or equal to the Eastern scarcity target level , but (ii) 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 \$40/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 \$40/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 (i) are less than or equal to the target level for that locational requirement, but (ii) 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 \$40/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 (i) are less than or equal to the Southeastern scarcity target level, but (ii) 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 \$40/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 (i) are less than or equal to the adjusted Southeastern target level, but (ii) 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 \$40/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 level, 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 (i) are less than or equal to the N.Y.C. scarcity target level, but (ii) 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 level, 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 (i) are less than or equal to the Long Island scarcity target level, but (ii) 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) or Aggregation(s) supplying any one of the Operating Reserves under ISO control. The Generator(s) or Aggregation(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) or Aggregation(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.

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 an Aggregation 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 or an Aggregation's capability or 10 percent of a CSR Scheduling Limit, or (ii) 100 MW of a Generator's or an Aggregation'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.

A Hybrid Storage Resource or an Operating Reserves-eligible Aggregation that only employs Energy Storage Resource DER to provide Operating Reserves will violate the withholding threshold whenever its Operating Reserve Limit is less than 75% of the minimum of (a) the HSR's or Operating Reserves-eligible Aggregation's Beginning Energy Level, or (b) the HSR's or Operating Reserves-eligible Aggregation's emergency ramp rate multiplied by the

time period over which the Operating Reserves would have been scheduled. Other compositions of Operating Reserves-eligible Aggregations will violate the withholding threshold whenever their Operating Reserve Limit is less than 75% of the minimum of the Operating Reserves-eligible Aggregation's emergency ramp rate multiplied by the time period over which the Operating Reserves would have been scheduled. Provided however, withholding less than 5 MW of Operating Reserves will not result in a violation.

For a Generator or an Aggregation 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 or Aggregation 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 or an Aggregation's capability or 10 percent of a CSR Scheduling Limit, or (ii) 50 MW of a Generator's or an Aggregation'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.

A Hybrid Storage Resource or Operating Reserves-eligible Aggregation that only employs Energy Storage Resource DER to provide Operating Reserves 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, will violate the withholding threshold whenever its Operating Reserve Limit is less than 75% of the minimum of (a) the HSR's or Operating Reserves-eligible Aggregation's Beginning Energy Level, or

(b) the HSR's or Operating Reserves-eligible Aggregation's emergency ramp rate multiplied by the time period over which the Operating Reserves would have been scheduled. Other compositions of Operating Reserves-eligible Aggregations will violate the withholding threshold whenever their Operating Reserve Limit is less than 75% of the minimum of the Operating Reserves-eligible Aggregation's emergency ramp rate multiplied by the time period over which the Operating Reserves would have been scheduled. Provided however, withholding less than 5 MW of Operating Reserves will not result in a violation.

23.3.1.1.1.2 Operating a Generator or generation or an Aggregation 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 or Aggregation followed the ISO's dispatch instructions, resulting in a difference in output that exceeds (i) 15 minutes times a Generator's or Aggregation's stated response rate per minute at the output level that would have been expected had the Generator or Aggregation followed the ISO's dispatch instructions, or (ii) 100 MW for a Generator or Aggregation, or (iii) 200 MW of the total capability of a Market Party and its Affiliates. For a Generator or an Aggregation or a Market Party in a Constrained Area for intervals in which an interface or facility into the area in which the generation or Aggregation is located has a Shadow Price greater than \$0.04/MWh, indicating an active constraint, operating a Generator or generation or an Aggregation 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 or Aggregation followed the ISO's dispatch instructions, resulting in a difference in output that exceeds (i) 15

minutes times a Generator's or an Aggregation's stated response rate per minute at the output level that would have been expected had the Generator or Aggregation followed the ISO's dispatch instructions, or (ii) 50 MW of a Generator's or an Aggregation'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 or an Aggregation'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 or an Aggregation 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 provide 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 and Aggregations 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 an Energy Storage Resource's or an Aggregation that consists solely of Energy

Storage Resources' 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. However, if the reference level spread is less than \$25 per MWh, then the Hourly Threshold shall be \$75 per MWh.

(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. However, if the reference level spread is less than \$25 per MWh, then the Hourly Threshold shall be \$75 per MWh.

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 or Aggregations containing 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 or Aggregations containing Withdrawal-Eligible Generator(s)).

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 or an Aggregation 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 or an Aggregation 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:

$$\text{Threshold} = \frac{2\% * \text{Average Price} * 8760}{\text{Constrained Hours}}$$

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 or Aggregation that is operating as Out-of-Merit Generation; and (c) to a Generator or an Aggregation 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 or Aggregation 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 or Aggregation 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 and Aggregations 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 or Aggregation 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 or Aggregation 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 or Aggregation 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 or Aggregation is the only Market Party that could effectively solve the reliability need for which the Generator or Aggregation was committed or dispatched, or
- ii when evaluating an SRE that was issued to address a reliability need that multiple Market Parties' Generators or Aggregations 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 or Aggregation prior to the close of the Day-Ahead Market.

23.3.1.2.3.3 The Bids or Bid components submitted for the Generator or Aggregation 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 or Aggregation'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 or Aggregations 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 the applicable reference level minus the greater of \$25 per MWh or 80% of the applicable reference level (*i.e.*, $LBMP < (\text{Applicable Reference Level} - \max(\$25, 80\% \times \text{Applicable Reference Level}))$); provided, however, the ISO shall not evaluate Generators to identify uneconomic production when the applicable LBMP is greater than \$25 per MWh; or

23.3.1.3.1.2 Real-time output from a Generator or generation or an Aggregation 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 or Aggregation 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 or an Aggregation's stated response rate per minute at the output level that would have been expected had the Generator or Aggregation followed the ISO's dispatch instructions, or (ii) 100 MW for a Generator or an Aggregation, 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 or Aggregations containing Withdrawal-Eligible Generator(s) 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 applicable reference level of a Withdrawal-Eligible Generator or of an Aggregation that contains Withdrawal-Eligible Generator(s); 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 or of an Aggregation that contains Withdrawal-Eligible Generator(s), 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 or an

Aggregation containing Withdrawal-Eligible Generator(s) resulting in different real-time operation than would have been expected had the Market Party's and the Affiliate's Generator or generation or Aggregation 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 or an Aggregation'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 an Aggregation, 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 or an Aggregation's Bid to provide 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 an Energy Storage Resource's or an Aggregation's Incremental Energy Bid to provide 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 or an Aggregation's operating costs in accordance with specifications provided by the ISO.

The reference level for a Generator's or an Aggregation's Energy and Ancillary Service Bids are intended to reflect the Generator's or Aggregation's marginal costs. The ISO's determination of a Generator's or Aggregation's Energy marginal costs shall include an assessment of the Generator's or Aggregation's incremental operating costs in accordance with the following formula:

$$\begin{aligned} & (\text{heat rate} * \text{fuel costs}) + (\text{emissions rate} * \text{emissions allowance price}) \\ & \quad + (\text{other variable operating and maintenance costs}) \\ & \quad + \text{opportunity costs} \end{aligned}$$

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 or Aggregation'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 and Aggregations, 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 or Aggregations 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 or Aggregations 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 or an Aggregation's reference level(s) when the Generator's or Aggregation'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 or an Aggregation'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 or Aggregation'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 or an Aggregation'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 or Aggregation 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 or Aggregation 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 or Aggregation's reference levels, and use the restored Bid(s) to determine a settlement. Otherwise the ISO shall use the Generator's or Aggregation'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 or Aggregation'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 or an Aggregation'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 or Aggregation's Bid(s) to develop reference levels for the affected Generator(s) or Aggregation(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 or an Aggregation to develop Day-Ahead or real-time reference levels for that Generator or Aggregation, 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 or an Aggregation to develop Day-Ahead or real-time reference levels for that Generator or an Aggregation, 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 or an Aggregation to develop Day-Ahead or real-time reference levels for that Generator or Aggregation, 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 or an Aggregation 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 or Aggregation 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 or an Aggregation 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 or Aggregation 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 or an Aggregation 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 or Aggregation is not the most economic fuel type available to the Generator or the relevant component(s) of the Aggregation, 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 or an Aggregation exceeded the fuel price that the ISO would have used to develop reference levels for that Generator or Aggregation 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 or Aggregation'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 or an Aggregation 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 or an Aggregation 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 or an Aggregation 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 or an Aggregation 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 or Aggregation's reference levels to the ISO in order to permit the revised costs to be timely reflected in the Generator or Aggregation reference levels. However, if the ISO uses published index prices to fuel index a Generator's reference level when that Generator or Aggregation 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. Withdrawal-Eligible Generators and Aggregations containing Withdrawal Eligible Generators 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 or Aggregation 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 or an

Aggregation's reference level(s) when changes in opportunity costs are expected to impact the Generator's or Aggregation'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 or Aggregation'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 or an Aggregation'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 or Aggregation 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 or Aggregation 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 or Aggregation's reference levels, and use the restored Bid(s) to determine a settlement. Otherwise the ISO shall use the Generator's or Aggregation'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 or an Aggregation'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 or an Aggregation'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

23.3.2.1.1.1 for uneconomic production or uneconomic withdrawal, a change (*i.e.*, the absolute value of the difference) of 200 percent or \$100 per MWh, whichever is lower, in the hourly Day-Ahead Energy LBMP, Real-Time Energy LBMP, or the Congestion Component of the Day-Ahead LBMP or the Real-Time LBMP at any location. Provided, however, the ISO shall not consider a price change of less than \$25 per MWh a material price effect for uneconomic production or uneconomic withdrawal; or

23.3.2.1.2 an increase of 200 percent, or 50 percent for Generators or Aggregations in a Constrained Area in Bid Production Cost guarantee payments to a Market Party for a Generator or an Aggregation for a day; or

23.3.2.1.2.1 for uneconomic production or uneconomic withdrawal, an increase of 200 percent, or 50 percent for Generators in a Constrained Area, in Bid Production Cost guarantee payments or Day-Ahead Margin Assurance Payments to a Market Party or to an Affiliate for a Generator for a day; or

23.3.2.1.3 for a Constrained Area Generator or Aggregation 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 or an Aggregation 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, Aggregation-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 or Aggregation's marginal costs or other Bid parameters may exceed the applicable 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) or Aggregation(s). If cost data or other information submitted by a

Market Party's Generator(s) or Aggregation(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 and Aggregations 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 and Aggregations, 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 or an Aggregation'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 or an Aggregation'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 or Aggregations containing Withdrawal-Eligible Generator(s), 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 and Aggregations 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 and Aggregations 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 or Aggregation'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 or Aggregation'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 or Aggregation'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 or Aggregation'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 or Aggregation's reference level(s) subject to the following prerequisites:

23.3.3.3.2.2.1 the Generator or Aggregation 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 or Aggregation'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 or Aggregation'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 or Aggregation incurred and shall apply mitigation if the Generator's or Aggregation'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 and Aggregations 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.

23.4 Mitigation Measures

23.4.1 Purpose and Terms

If conduct is detected that meets the criteria specified in Section 23.3, the appropriate mitigation measure described in this Section shall be applied by the ISO. The conduct specified in Sections 23.3.1.1 to 23.3.1.3 shall be remedied by (1) the prospective application of a default bid measure, or (2) the application of a default bid to correct guarantee payments, as further described in Section 23.4.2.2.4, below, or (3) the application of the sanction described in Section 23.4.3 of these Mitigation Measures if (x) an Energy Storage Resource, or an Aggregation made up solely of Energy Storage Resources located outside the Constrained Area engages in conduct that violates Section 23.3.1.2.1.1.2(a) of these Mitigation Measures that has an LBMP impact that exceeds the applicable threshold, or (y) an Energy Storage Resource, or an Aggregation made up solely of Energy Storage Resources engages in conduct that violates Sections 23.3.1.2.1.1.2(b) or 23.3.1.2.2.6(b) of these Mitigation Measures that has an LBMP impact that exceeds the applicable threshold in the Day-Ahead Market. If a Market Party or its Affiliates (i) engage in physical withholding by providing the ISO false information regarding the derating or outage of an Electric Facility, or (ii) engage in uneconomic production or uneconomic withdrawal or do not operate a Generator or an Aggregation in conformance with ISO dispatch instructions such that the prospective application of a default bid is not feasible, or (iii) if otherwise appropriate to deter physical or economic withholding or uneconomic production or uneconomic withdrawal, the ISO shall apply the sanction described in Section 23.4.3.

Terms with initial capitalization not defined in Section 23.4 shall have the meaning set forth in the Open Access Transmission Tariff.

23.4.2 Default Bid

23.4.2.1 Purpose

A default bid shall be designed to cause a Market Party to Bid as if it faced workable competition during a period when (i) the Market Party does not face workable competition, and (b) has responded to such condition by engaging in the physical or economic withholding of an Electric Facility. In designing and implementing default bids, the ISO shall seek to avoid causing an Electric Facility to Bid below its marginal cost.

23.4.2.2 Implementation

23.4.2.2.1 If the criteria contained in Section 23.3 are met, the ISO may substitute a default bid or bid parameter for a Bid or bid parameter submitted for an Electric Facility, or require the Market Party to use the default bid or bid parameter in the Bids it submits for an Electric Facility. The default bid or bid parameter shall establish a maximum or minimum value for one or more components of the submitted Bid or Bid parameters, equal to a reference level for that component determined as specified in Section 23.3.1.4.

23.4.2.2.1.1 If the substitution of a default bid or bid parameter(s) for any portion of the Incremental Energy Bid curve submitted for an Energy Storage Resource would result in a mitigated energy curve that is not consistent with the Energy Storage Resource's Roundtrip Efficiency, then the default bid or bid parameter(s) to inject Energy will be adjusted to the minimum extent necessary to ensure the difference between bids to withdraw Energy and bids to inject Energy incorporate the Energy Storage Resource's Roundtrip Efficiency.

23.4.2.2.2 An Electric Facility subject to a default bid shall be paid the LBMP or other market clearing price applicable to the output from the facility.

Accordingly, a default bid shall not limit the price that a facility may receive unless the default bid determines the LBMP or other market clearing price applicable to that facility.

23.4.2.2.3 If an Electric Facility is mitigated using the automated mitigation procedures described in Section 23.3.2.2.3 of these mitigation measures to a default bid for an Incremental Energy Bid other than a default bid determined as specified in Section 23.3.1.4, the Electric Facility shall receive an additional payment for each interval in which such mitigation occurs equal to the product of: (i) the amount of Energy in that interval scheduled or dispatched to which the incorrect default bid was applied; (ii) the difference between (a) the lesser of the applicable unmitigated bid and a default bid determined in accordance with Section 23.3.1.4, and (b) the applicable LBMP or other relevant market price in each such interval, if (a) greater than (b), or zero otherwise; and (iii) the length of that interval.

If an Electric Facility is mitigated to a default bid for a Start-Up Bid or a Minimum Generation Bid other than a default bid determined as specified in Section 23.3.1.4 of these Mitigation Measures, or if an Electric Facility is mitigated to a default bid for an Incremental Energy Bid other than a default bid determined as specified in Section 23.3.1.4 of these Mitigation Measures based on mitigation procedures other than the automated mitigation procedures described in Section 23.3.2.2.3 of these Mitigation Measures, then the ISO shall determine

if the Bids would have failed the relevant conduct test(s) if correctly determined default bids had been used. The ISO shall then restore any original (as-submitted) Bid(s) that would not have failed the relevant conduct test(s) if correctly determined default bids had been used, and use the restored Bid(s) to determine a settlement. Otherwise, the ISO shall use the Generator's or Aggregation's correct or corrected default bid(s) to determine a settlement.

23.4.2.2.4 Except as may be specifically authorized by the Commission:

23.4.2.2.4.1 The ISO shall not use a default bid to determine revised market clearing prices for periods prior to the imposition of the default bid.

23.4.2.2.4.2 The ISO shall only be permitted to apply default bids to determine revised real-time guarantee payments to a Market Party in accordance with the provisions of Section 23.3.3.3 of these Mitigation Measures.

23.4.2.2.5 Automated implementation of default bid mitigation measures shall be subject to the following requirements.

23.4.2.2.5.1 Automated mitigation measures shall not be applied if the price effects of the measures would cause the average day-ahead energy price in the mitigated locations or zones to rise over the entire day.

23.4.2.2.5.2 Automated mitigation measures as specified in Section 23.3.2.2.3 shall be applied to Minimum Generation Bids and start-up costs Bids meeting the applicable conduct and impact tests. When mitigation of Minimum Generation Bids is warranted, mitigation shall be imposed from the first hour in which the impact test is met to the last hour in which the impact test is met, or for the duration of the mitigated Generator's minimum run time, whichever is longer.

23.4.2.2.5.3 The posting of the Day-Ahead schedule may be delayed if necessary for the completion of automated mitigation procedures.

23.4.2.2.5.4 Bids not mitigated under automated procedures shall remain subject to mitigation by other procedures specified herein as may be appropriate.

23.4.2.2.5.5 The role of automated mitigation measures in the determination of Day-Ahead market clearing prices is described in Section 17.1.3 of Attachment B of the ISO Services Tariff.

23.4.2.2.6 A Real-Time automated mitigation measure shall remain in effect for the duration of any hour in which there is an RTC interval for which such mitigation is deemed warranted.

23.4.2.2.7 A default bid shall not be imposed on a Generator that is not in the New York Control Area and that is electrically interconnected with another Control Area.

23.4.3 Sanctions

23.4.3.1 Types of Sanctions

The ISO may impose financial penalties on a Market Party in amounts determined as specified below.

23.4.3.2 Imposition

The ISO shall impose financial penalties as provided in this Section 23.4.3, if the ISO determines in accordance with the thresholds and other standards specified in this Attachment H that: (i) a Market Party has engaged in physical withholding, including providing the ISO false information regarding the derating or outage of an Electric Facility; or (ii) a Market Party or its Affiliates have engaged in uneconomic production; or (iii) a Market Party or its Affiliates have

engaged in uneconomic withdrawal; or (iv) a Market Party or its Affiliates have failed to follow the ISO's dispatch instructions in real-time, resulting in a different output level than would have been expected had the Market Party's or the Affiliate's generation followed the ISO's dispatch instructions, and such conduct has caused a material increase in one or more prices or guarantee payments in an ISO Administered Market; or (v) a Market Party has made unjustifiable changes to one or more operating parameters of a Generator or an Aggregation that reduce its ability to provide Energy or Ancillary Services; or (vi) a Load Serving Entity has been subjected to a Penalty Level payment in accordance with Section 23.4.4 below; or (vii) a Market Party has submitted inaccurate fuel type or fuel price or opportunity cost information that is used by the ISO in the development of a Generator's or an Aggregation's reference level, where the inaccurate reference level that is developed, in turn, directly or indirectly impacts guarantee payments or market clearing prices paid to the Market Party; or (viii) a Market Party has submitted inaccurate information other than fuel type or fuel price information that is used by the ISO in the development of a Generator's or an Aggregation's reference level, where the inaccurate reference level that is developed, in turn, directly or indirectly impacts guarantee payments or market clearing prices paid to the Market Party; or (ix) the opportunity to submit Incremental Energy Bids into the real-time market that exceed Incremental Energy Bids made in the Day-Ahead Market or mitigated Day-Ahead Incremental Energy Bids where appropriate, has been revoked for a Market Party's Generator or Aggregation pursuant to Sections 23.4.7.2 and 23.4.7.3 of these Mitigation Measures; or (x) a Market Party has engaged in economic withholding in the Day-Ahead Market by submitting Incremental Energy Bids that 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 and cause an LBMP impact that exceeds the applicable threshold; or (xi) a Market

Party has engaged in economic withholding of an Energy Storage Resource or an Aggregation made up solely of Energy Storage Resources located outside the Constrained Area by submitting Incremental Energy Bids that violate the conduct threshold specified in Section 23.3.1.2.1.1.2(a) of these Mitigation Measures and cause an LBMP impact that exceeds the applicable threshold; or (xii) a Market Party has withheld Operating Reserves that a Hybrid Storage Resource or Operating Reserves-eligible Aggregation is capable of providing by submitting an Operating Reserve Limit that violates the conduct threshold specified in Section 23.3.1.1.1.1 of these Mitigation Measures and causes a market clearing price impact that exceeds the applicable threshold.

23.4.3.3 Base Penalty Amount

23.4.3.3.1 Except for financial penalties determined pursuant to Sections 23.4.3.3.2, 23.4.3.3.3, and 23.4.3.3.4 below, financial penalties shall be determined by the product of the Base Penalty Amount, as specified below, times the appropriate multiplier specified in Section 23.4.3.4:

MW meeting the standards for mitigation during Mitigated Hours * Penalty market-clearing price.

23.4.3.3.1.1 For purposes of determining a Base Penalty Amount, the term “Mitigated Hours” shall mean: (i) for a Day-Ahead Market, the hours in which MW were withheld; (ii) for a Real-Time Market, the hours in the calendar day in which MW were withheld; and (iii) for load Bids, the hours giving rise to Penalty Level payments.

23.4.3.3.1.1.1 For purposes of determining a Base Penalty Amount for economic withholding related to Bids that the ISO evaluates as a price spread for purposes of scheduling and dispatch, the term “Mitigated Hours” shall instead mean:

- (i) for the Day-Ahead Market, for Energy Storage Resources and Aggregations made up solely of Energy Storage Resources located outside the Constrained Area, all hours of the day in which an LBMP impact is determined after the NYISO replaces all Incremental Energy Bids that violate the conduct thresholds specified in Sections 23.3.1.2.1.1.2(a) or 23.3.1.2.1.1.2(b) of these Mitigation Measures with reference levels; or
- (ii) for the Day-Ahead Market, for Energy Storage Resources and Aggregations made up solely of Energy Storage Resources located in the Constrained Area, all hours of the day in which an LBMP impact is determined after the NYISO replaces all Incremental Energy Bids that violate the conduct thresholds specified in Section 23.3.1.2.2.6(b) of these Mitigation Measures with reference levels; or
- (iii) for the Real-Time Market, for Energy Storage Resources and Aggregations made up solely of Energy Storage Resources located outside the Constrained Area, all hours of the day in which an LBMP impact is determined after the NYISO replaces all Incremental Energy Bids that violate the conduct thresholds specified in Sections 23.3.1.2.1.1.2(a) of these Mitigation Measures with reference levels.

In each of the above cases, the “MW meeting the standards for mitigation during Mitigated Hours” shall be all scheduled MW.

23.4.3.3.1.2 For purposes of determining a Base Penalty Amount, the term “Penalty market-clearing price” shall mean: (i) for a withholding seller, the LBMP or other market-clearing price at the generator bus of the withheld resource (or in the relevant Load Zone, if a clearing price is not calculated at the generator bus); and (ii) for a Load Serving Entity, its zonal LBMP.

23.4.3.3.1.2.1 For purposes of determining a Base Penalty Amount for economic withholding related to Bids that the ISO evaluates as a price spread for purposes of scheduling and dispatch, the “Penalty market-clearing price” shall instead mean the difference between the market clearing price that was set and the market clearing price would instead be determined if reference levels are substituted for conduct-failing Incremental Energy Bids.

23.4.3.3.1.3 For purposes of determining the “MW meeting the standards for mitigation during Mitigated Hours” the ISO shall exclude the Lower Storage Limit of an Energy Storage Resource that is a component of a Hybrid Storage Resource or of an Operating Reserves-eligible Aggregation that is not entirely comprised of Energy Storage Resources when the ISO is calculating a penalty for withholding Operating Reserves.

23.4.3.3.2 Uneconomic Production, Uneconomic Withdrawal, and Failure to Follow ISO Dispatch Instructions

23.4.3.3.2.1 The financial penalty for uneconomic production conduct that violates the thresholds set forth in 23.3.1.3.1.1 of these Mitigation Measures or uneconomic withdrawal conduct that violates the thresholds set forth in 23.3.1.3.2.1 of these Mitigation Measures, and is determined to have had impact in accordance with Section 23.3.2.1 of these Mitigation Measures, shall be:

(i) One and a half times the product of (a) the absolute value of the Congestion Component of the Day-Ahead LBMP or Real-Time LBMP and (b) the MW meeting the standards for mitigation during the Mitigated Hour(s); or

(ii) One and a half times the increase in Bid Production Cost guarantee payments or Day-Ahead Margin Assurance Payments earned by the Generator or by the Market Party and its Affiliates during the Mitigated Hour(s), or on the market day during which the Mitigated Hour(s) occurred if related to a daily payment.

For purposes of determining the financial penalty for uneconomic production or uneconomic withdrawal in this Section 23.4.3.3.2.1, the term “Mitigated Hour(s)” shall mean the hours in which uneconomic production or uneconomic withdrawal conduct occurred.

23.4.3.3.2.2 The financial penalty for failure to follow ISO’s dispatch instructions in real-time, resulting in real-time operation at a different output level than would have been expected had the Market Party’s or the Affiliate’s generation followed the ISO’s dispatch instructions, if the conduct violates the thresholds set forth in Sections 23.3.1.1.1.2, or 23.3.1.3.1.2 of these Mitigation Measures, and if a Market Party or its Affiliates, or at least one Generator or Aggregation, is determined to have had impact in accordance with Section 23.3.2.1 of these Mitigation Measures, shall be:

One and a half times the estimated additional real time LBMP and Ancillary Services revenues earned by the Generator or Aggregation, or Market

Party and its Affiliates, meeting the standards for impact during intervals in which MW were not provided or were overprovided.

23.4.3.3.3 Submission of Inaccurate Fuel Type, Fuel Price or Opportunity Cost Information

If inaccurate fuel type, fuel price or opportunity cost information was submitted by or for a Market Party, and the reference level that the ISO developed based on that inaccurate information impacted guarantee payments or market clearing prices paid to the Market Party in a manner that violates the thresholds specified in this Section 23.4.3.3.3, then, following consultation with the Market Party regarding the appropriate fuel type, fuel price or opportunity cost, the ISO shall apply the penalty set forth below, unless: (i) the Market Party shows that the information was submitted in compliance with the requirements of Section 4.1.9 of the ISO Services Tariff (Cost Recovery for Units Responding to Local Reliability Rules Addressing Loss of Generator Gas Supply), or (ii) the total penalty calculated for a particular Day-Ahead or Real-Time Market day is less than \$5,000, in which case the ISO will not apply a penalty.

23.4.3.3.3.1 Inaccurate Fuel Type and/or Fuel Price Information Conduct and Market Impact Tests

23.4.3.3.3.1.1 Inaccurate Fuel Type and/or Fuel Price Information Conduct Test and Inaccurate Opportunity Cost Conduct Test

Inaccurate Fuel Price/Type Conduct Test—using the higher of (a) a revised reference level calculated using the Generator's or Aggregation's actual fuel costs, or (b) the reference level that would have been in place for the Generator or Aggregation but for the submission of inaccurate fuel type and/or

fuel price information, test the Bids to determine if they violate the relevant conduct threshold in accordance with the appropriate provision(s) of Section 23.3.1.2 of these Mitigation Measures.

Inaccurate Opportunity Cost Conduct Test—using the higher of (a) a revised reference level calculated using the Generator’s or Aggregation’s demonstrated opportunity cost, or (b) the reference level that would have been in place for the Generator or Aggregation but for the submission of inaccurate opportunity cost information, test the Bids to determine if they violate the relevant conduct threshold in accordance with the appropriate provision(s) of Section 23.3.1.2 of these Mitigation Measures.

23.4.3.3.1.2 Inaccurate Fuel Type and/or Fuel Price Information Impact Test and Inaccurate Opportunity Cost Conduct Test

Inaccurate Fuel Price/Type Impact Test—using the higher of (a) a revised reference level calculated using the Generator’s or Aggregation’s actual fuel costs, or (b) the reference level that would have been in place for the Generator or Aggregation but for the submission of inaccurate fuel type and/or fuel price information, test the Bids for both LBMP and guarantee payment impact in accordance with the appropriate provisions of Section 23.3.2.1 of these Mitigation measures.

Inaccurate Opportunity Cost Impact Test—using the higher of (a) a revised reference level calculated using the Generator’s or Aggregation’s demonstrated opportunity cost, or (b) the reference level that would have been in place for the Generator or Aggregation but for the submission of inaccurate opportunity cost information, test the Bids for both LBMP and guarantee payment

impact in accordance with the appropriate provisions of Section 23.3.2.1 of these Mitigation measures.

23.4.3.3.3.1.2.1 The ISO shall perform the guarantee payment impact tests for Generators or Aggregations that are committed in the Day-Ahead Market for local reliability or in the Real-Time Market via an SRE, and that are not located in a Constrained Area, at the 50% increase Constrained Area threshold specified in Section 23.3.2.1.2 of these Mitigation Measures.

23.4.3.3.3.1.3 Day-Ahead Reliability Commitments in a Constrained Area

Consistent with Section 23.5.2 of these Mitigation Measures, the conduct and impact thresholds for In-City Generators or Aggregations committed in the Day-Ahead Market for local reliability shall each be zero.

23.4.3.3.3.2 Inaccurate Fuel Type and/or Fuel Price and/or Opportunity Cost Information Penalty Calculation

If the results of the impact test indicate that the Market Party's Bid had either LBMP or guarantee payment impact then the ISO shall charge the Market Party a penalty, calculated separately for the Day-Ahead Market and the Real-Time Market for each penalized day, for each of its Generators or Aggregations, as follows:

Daily Penalty (for either the Day-Ahead Market or the Real-Time Market) =

$$\begin{aligned} & \text{Multiplier} \times \max [\sum_g \blacktriangle \text{BPCG payment}_g + \\ & \sum_h \sum_g (\text{Market Party MWh}_{gh} \times \blacktriangle \text{LBMP@PTID}_{gh}) + \\ & \max (\sum_h \text{TCC Revenue Calc for Market Party}_h, 0), 0] \end{aligned}$$

Where:

g = each of the Market Party's Generators or Aggregations.

h = (a) for the purpose of calculating Day-Ahead Market penalties for a given day, h is each hour of that day in which inaccurate fuel type or fuel price or opportunity cost information was supplied in the Day-Ahead Market for any of the Market Party's Generators or Aggregations, provided that one of the Day-Ahead Bids in that hour "h" for at least one of the Market Party's Generators or Aggregations failed an LBMP or guarantee payment impact test described in Section 23.4.3.3.3.1.2 of these Mitigation Measures, or (b) for the purpose of calculating Real-Time Market penalties for a given day, h is each hour of that day in which inaccurate fuel type or fuel price or opportunity cost information was supplied in the Real-Time Market for any of the Market Party's Generators or Aggregations, provided that one of the Real-Time Bids in that hour "h" for at least one of the Market Party's Generators or Aggregations failed an LBMP or guarantee payment impact test described in Section 23.4.3.3.3.1.2 of these Mitigation Measures.

Multiplier = a factor of 1.0 or 1.5. Determined as specified below.

For violations related to fuel price and/or fuel type submissions, the ISO shall use a 1.0 Multiplier if the Market Party has not been penalized for inaccurately reporting fuel type or fuel price information over the 6 months prior to the market-day for which the penalty is being calculated. In all other cases the ISO shall use a 1.5 Multiplier.

For violations related to opportunity cost submissions, the ISO shall use a 1.0 Multiplier if the Market Party has not been penalized for inaccurately reporting opportunity cost information over the 6 months prior to the market-day for which

the penalty is being calculated. In all other cases the ISO shall use a 1.5 Multiplier.

▲ $BPCG_{payment_g}$ = (a) for the purpose of calculating Day-Ahead Market penalties for a given day, the change in the Day-Ahead Market guarantee payment for that day for Generator or Aggregation g determined when the ISO performs the guarantee payment impact test in accordance with Section 23.3.2.1.2 of these Mitigation Measures, or (b) for the purpose of calculating Real-Time Market penalties for a given day, the change in the Real-Time guarantee payment for that day for Generator or Aggregation g determined when the ISO performs the guarantee payment impact test in accordance with Section 23.3.2.1.2 of these Mitigation Measures.

Market Party MWh_{gh} = (a) for the purpose of calculating Day-Ahead Market penalties, the MWh of Energy scheduled in the Day-Ahead Market for Generator or Aggregation g in hour h; or (b) for the purpose of calculating Real-Time Market penalties, the maximum of (1) the MWh of Energy that Generator or Aggregation g was scheduled to provide in the Day-Ahead Market in hour h, or (2) the MWh of Energy that Generator or Aggregation g was scheduled to provide in the Real-Time Market in hour h, or (3) the MWh of Energy produced by Generator or Aggregation g that was scheduled to provide energy in hour h in the Real-Time Market.

▲ $LBMP@PTID_{gh}$ = (a) for the purpose of calculating Day-Ahead Market penalties, the change in the Day-Ahead Market LBMP for hour h at the location of Generator or Aggregation g, as determined when the ISO performs the relevant

LBMP impact test in accordance with Section 23.3.2.1.1 or 23.3.2.1.3 of these Mitigation Measures, or (b) for the purpose of calculating Real-Time Market penalties, the change in the real-time LBMP for hour h at the location of Generator or Aggregation g, as determined when the ISO performs the relevant LBMP impact test in accordance with Section 23.3.2.1.1 or 23.3.2.1.3 of these Mitigation Measures.

TCC Revenue Calc for Market Party_h = (a) for the purpose of calculating Day-Ahead Market penalties, the change in TCC Revenues that the Market Party receives for hour h, determined when the ISO performs the relevant Day-Ahead Market LBMP impact test, or (b) for the purpose of calculating Real-Time Market penalties, zero.

23.4.3.3.4 Virtual Bidding Penalties

23.4.3.3.4.1 If the opportunity to submit Incremental Energy Bids into the Real-Time Market that exceed Incremental Energy Bids made in the Day-Ahead Market or mitigated Day-Ahead Incremental Energy Bids where appropriate, has been revoked on a Market Party's Generator or Aggregation pursuant to Sections 23.4.7.2 and 23.4.7.3 of these Mitigation Measures, then the following virtual market penalty may be imposed on the Market Party:

Virtual market penalty = (Virtual Load MWs) * (Amount by which the hourly integrated real-time LBMP exceeds the day-ahead LBMP applicable to the Virtual Load MWs)

WHERE:

Virtual Load MWs are the scheduled MWs of Virtual Load Bid by the Market Party in the hour for which an increased real-time Bid for the Market Party's Generator or Aggregation failed the test specified in Section 23.4.7.2 of these Mitigation Measures; and

LBMP is the LBMP at which the Virtual Load MWs settled in the Day-Ahead and real-time Markets.

23.4.3.3.4.2 If the opportunity to submit Incremental Energy Bids into the Real-Time Market that are less than the Incremental Energy Bids submitted in the Day-Ahead Market (or the mitigated Day-Ahead Incremental Energy Bids where appropriate), has been revoked on a Market Party's Generator or Aggregation pursuant to Sections 23.4.7.2 and 23.4.7.3 of these Mitigation Measures, then the following virtual market penalty may be imposed on the Market Party:

Virtual market penalty = (Virtual Supply MWs) * (Amount by which the hourly integrated real-time LBMP is less than the day-ahead LBMP applicable to the Virtual Supply MWs)

WHERE:

Virtual Supply MWs are the scheduled MWs of Virtual Supply Bid by the Market Party in the hour for which a reduced real-time Bid for the Market Party's Generator or Aggregation failed the test specified in Section 23.4.7.2 of these Mitigation Measures; and

LBMP is the LBMP at which the Virtual Supply MWs settled in the Day-Ahead and real-time Markets.

23.4.3.3.5 No Revisions to Real-Time LBMPs

Real-Time LBMPs shall not be revised as a result of the imposition of a financial obligation as specified in this Section 23.4.3.3, except as may be specifically authorized by the Commission.

23.4.3.4 Multipliers

The Base Penalty Amount specified in Section 23.4.3.3.1 shall be subject to the following multipliers:

23.4.3.4.1 For the first instance of a type of conduct by a Market Party meeting the standards for mitigation, the multiplier shall be one (1).

23.4.3.4.2 For the second instance within the current or the two immediately previous capability periods of substantially similar conduct in the same market by a Market Party or its Affiliates, the multiplier shall be one (1),

23.4.3.4.3 For the third instance within the current or the two immediately previous capability periods of substantially similar conduct in the same market by a Market Party or its Affiliates, the multiplier shall be two (2),

23.4.3.4.4 For the fourth or any additional instance within the current or immediately previous capability period of substantially similar conduct in the same market by a Market Party or its Affiliates, the multiplier shall be three (3).

23.4.3.5 Dispute Resolution

23.4.3.5.1 Parties with of disputes arising from or relating to the imposition of a sanction under this Section 23.4.3 may utilize the dispute resolution provisions of the ISO Services Tariff. The scope of any such proceeding shall include resolution of any dispute as to legitimate justifications, under applicable legal,

regulatory or policy standards, for any conduct that is asserted to warrant a penalty. Any or all of the issues in any such proceeding may be resolved by agreement of the parties.

23.4.3.5.2 Payment of a financial penalty may be withheld pending conclusion of any arbitration or other alternate dispute resolution proceeding instituted pursuant to the preceding paragraph and any petition to FERC for review under the Federal Power Act of the determination in such dispute resolution proceeding; provided, however, that interest at the ISO's average cost of borrowing shall be payable on any part of the penalty that is withheld, and that is determined to be payable at the conclusion of the dispute resolution/FERC review process from the date of the infraction giving rise to the penalty to the date of payment. The exclusive remedy for the inappropriate imposition of a financial penalty, to the exclusion of any claim for damages or any other form of relief, shall be a determination that a penalty should not have been imposed, and a refund with interest of paid amounts of a penalty determined to have been improperly imposed, as may be determined in the applicable dispute resolution proceedings.

23.4.3.5.3 This Section 23.4.3 shall not be deemed to provide any right to damages or any other form of relief that would otherwise be barred by Section 30.11 of Attachment O or Section 23.6 of this Attachment H.

23.4.3.5.4 This Section 23.4.3 shall not restrict the right of any party to make such filing with the Commission as may otherwise be appropriate under the Federal Power Act.

23.4.3.6 Disposition of Penalty Funds

Except as specified in Section 23.4.4.3.2, amounts collected as a result of the imposition of financial penalties shall be credited against costs collectable under Rate Schedule 1 of the ISO Services Tariff.

23.4.4 Load Bid Measure

23.4.4.1 Purpose

As initially implemented, the ISO market rules allow loads to choose to purchase power in either the Day-Ahead Market or in the Real-Time Market, but provide other Market Parties less flexibility in opting to sell their output in the Real-Time Market. As a result of this and other design features, certain bidding practices may cause Day-Ahead LBMPs not to achieve the degree of convergence with Real-Time LBMPs that would be expected in a workably competitive market. A temporary mitigation measure is specified below as an interim remedy if conditions warrant action by the ISO until such time as the ISO develops and implements an effective long-term remedy, if needed. These measures shall only be imposed if persistent unscheduled load causes operational problems, including but not limited to an inability to meet unscheduled load with available resources. The ISO shall post a description of any such operational problem on its web site.

23.4.4.2 Implementation

23.4.4.2.1 Day-Ahead LBMPs and Real-Time LBMPs in each load zone shall be monitored to determine whether there is a persistent hourly deviation between them in any zone that would not be expected in a workably competitive market. Monitoring of Day-Ahead and real-time LBMPs shall include examination of the following two metrics (along with any additional monitoring tools and procedures

that the ISO determines to be appropriate to achieve the purpose of this Section 23.4.4):

(1) The ISO shall compute a rolling average of the hourly deviation of real-time zonal LBMPs from Day-Ahead zonal LBMPs. The hourly deviation shall be measured as: $(\text{zonal LBMP}_{\text{real time}} - \text{zonal LBMP}_{\text{day ahead}})$. Each observation of the rolling-average time series shall be a simple average of all the hourly deviations over the previous four weeks, or such other averaging period determined by the ISO to be appropriate to achieve the purpose of this Section 23.4.4.

(2) The ISO shall also compute the rolling average *percentage* deviation of real-time zonal LBMPs from Day-Ahead zonal LBMPs. This percentage deviation shall be calculated by dividing the rolling-average hourly deviation (defined in Section 23.4.4.2.1 (1) above) by the rolling-average level of Day-Ahead zonal LBMP over the same time period, using the averaging period(s) described in Section 23.4.4.2.1 (1), above.

23.4.4.2.2 The ISO shall also estimate and monitor the average percentage of each Load Serving Entity's load scheduled in the Day-Ahead Market, using a methodology intended to identify a sustained pattern of under-bidding as accurately as the ISO deems practicable. The average percentage will be computed over a specified time period determined by the ISO to be appropriate to achieve the purpose of this mitigation measure.

23.4.4.2.3 If the ISO determines that (i) the relationship between zonal LBMPs in a zone in the Day-Ahead Market and the Real-Time Market is not what would be expected under conditions of workable competition, (ii) one or more Load

Serving Entities have been meeting a substantial portion of their loads with purchases in the Real-Time Market, and (iii) that this practice has contributed to an unwarranted divergence of LBMP between the two markets, then the following mitigation measure may be imposed. Any such measure shall be rescinded upon a determination by the ISO that any one or more of the foregoing conditions is not met.

23.4.4.3 Description of the Measure

23.4.4.3.1 The ISO may require a Load Serving Entity engaging in the purchasing practice described above to purchase or schedule all of its expected power requirements in the Day-Ahead Market. A Load Serving Entity subject to this requirement may purchase up to a specified portion of its actual load requirements (the “Allowance Level”) in the Real-Time Market without penalty, as determined by the ISO to be appropriate in recognition of the uncertainty of load forecasting.

23.4.4.3.2 Effective with the imposition of the foregoing requirement, all purchases in the Real-Time Market in excess of this Allowance Level (the “Penalty Level”) shall be settled at a specified premium over the applicable zone LBMP. Revenues from such premiums, if any, shall be rebated on a *pro rata* basis to the Market Parties that scheduled energy for delivery to load within New York in the Day-Ahead Market for the day in which the revenues were collected.

23.4.4.3.3 The Allowance Level and the Penalty Level shall be established by the ISO at levels deemed effective and appropriate to mitigate the market effects described in this Section 23.4.4. In addition, the Penalty Level payments shall be

waived in any hour in which the Allowance Level is exceeded because of
unexpected system conditions.

30.6 Data Collection and Disclosure

30.6.1 Access to ISO Data and Information

For purposes of carrying out their responsibilities under Attachment O, the Market Monitoring Unit and MMA shall have access to, and shall endeavor primarily to rely upon (but shall not be limited to), data or other information gathered or generated by the ISO in the course of its operations. This data and information shall include, but not be limited to, data or information gathered or generated by the ISO in connection with its scheduling, commitment and dispatch of supply, its determination of Locational Based Marginal Pricing, its operation or administration of the New York State Transmission System, and data or other information produced by, or required to be provided to the ISO under its Tariffs, the New York Independent System Operator Agreement, the New York State Reliability Council Agreement, or any other relevant tariffs or agreements.

30.6.2 Data from Market Parties

30.6.2.1 Data Requests

If the Market Monitoring Unit or MMA, determines that additional data or other information is required to accomplish the objectives of Attachment O or of the Market Mitigation Measures, the ISO may request the persons or entities possessing, having access to, or having the ability to generate or produce such data or other information to furnish it to the ISO or to its Market Monitoring Unit. Any such request shall be accompanied by an explanation of the need for such data or other information, a specification of the form or format in which the data is to be produced, and an acknowledgment of the obligation of the ISO and its Market Monitoring Unit to maintain the confidentiality of data or information appropriately designated as Protected Information by the party producing it.

A party receiving an information request from the ISO shall furnish all information, in the requested form or format, that is: (i) included on the below list of categories of data or information that it may routinely request from a Market Party; or (ii) reasonably necessary to achieve the purposes or objectives of Attachment O, not readily available from some other source that is more convenient, less burdensome and less expensive, and not subject to an attorney-client or other generally recognized evidentiary doctrine of confidentiality or privilege.

The categories data or information that may be routinely requested shall be limited to data or information the routine provision of which would not be unduly burdensome or expensive, and which has been reasonably determined by the ISO, in consultation with its Market Monitoring Unit, to be likely to be relevant to the purposes and objectives of Attachment O or the Market Mitigation Measures.

30.6.2.2 Categories of Data the ISO May Request from Market Parties

The following categories of data or information may be obtained by the ISO from Market Parties in accordance with Attachment O. Market Parties shall retain the following categories of data or information for the period specified in Section 30.6.3 of Attachment O.

30.6.2.2.1 Production costs – Data or information relating to the costs or operating a specified Electric Facility (for generating units such data or information shall include, but not be limited to, heat rates, start-up fuel requirements, fuel purchase costs, and operating and maintenance expenses) or data or information relating to the costs of providing load reductions from a specified facility participating as a Demand Side Resource in the ISO Energy, Operating Reserves or Regulation Service markets.

30.6.2.2.2 Opportunity costs – Data or information relating to a claim of opportunity costs, including, but not limited to, contracts or price quotes.

30.6.2.2.3 Logs – Data or information relating to the operating status of an Electric Facility, including, for generating units, generator logs showing the generating status of a specified unit or data or information relating to the operating status of a specified facility participating as a Demand Side Resource in the ISO Energy, Operating Reserves or Regulation Service markets. Such data or information shall include, but not be limited to, any information relating to the validity of a claimed forced outage or derating of a generating unit or other Electric Facility or a facility participating as a Demand Side Resource in the ISO Energy, Operating Reserves or Regulation Service markets, including information related to the submission of an Operating Reserve Limit.

30.6.2.2.4 Bidding or Capacity Agreements – Documents, data, or information relating to a Market Party or its Affiliate conveying to or receiving from another entity the ability: (i) to determine the bid/offer of (in any of the markets administered by the ISO); (ii) to determine the output level of; or (iii) to withhold; generation that is owned by another entity. At the request of the producing entity, the ISO may (but is not required to) permit the documents, data or information produced in response to the foregoing specification to be partially redacted, or the ISO may agree to other measures for the protection of confidential or commercially sensitive information, provided that the ISO receives the complete text of all provisions relating to the subjects specified in this Section 30.6.2.2.4

30.6.2.2.5 Other Cost and Risk Data Supporting Reference Levels or ICAP

mitigation determinations or Going-Forward Costs – All data or information not specifically identified above that: (i) supports or relates to a Market Party's claimed, requested, or approved reference levels or Going-Forward Costs (as that term is defined in the Market Mitigation Measures) for a particular resource; or (ii) are necessary for the ISO to make a mitigation determination under Services Tariff Section 23.4.5.7, including data or information: (a) necessary to determine a Market Party's Unit Net CONE (as that term is defined in the Market Mitigation Measures) for a particular resource; or (b) required to evaluate a Market Party for a mitigation determination, including information from a Market Party's Affiliates, as appropriate.

30.6.2.2.6 Information Related to RMR Agreements -- All information that the NYISO is authorized to obtain under Appendix B to Attachment FF to the OATT.

30.6.2.2.7 Ownership and Control – Data or information identifying a Market Party's Affiliates.

30.6.2.3 Enforcement of Data Requests

30.6.2.3.1 A party receiving a request for data or information specified in Section 30.6.2.2 of Attachment O shall promptly provide it to the ISO, and may not contest the right of the ISO to obtain such data or information except to the extent that the party has a good faith basis to assert that the data or information is not included in any of the categories on the list.

30.6.2.3.2 If a party receiving a request for data or information not specified in Section 30.6.2.2 of Attachment O believes that production of the requested data or

information would impose a substantial burden or expense, or would require the party to produce information that is not relevant to achieving the purposes or objectives of Attachment O, or would require the production of data or information of extraordinary commercial sensitivity, the party receiving the request shall promptly so notify the ISO, and the ISO shall review the request with the receiving party with a view toward determining whether, without unduly compromising the objectives of Attachment O, the request can be narrowed or otherwise modified to reduce the burden or expense of compliance, or special confidentiality protections are warranted, and if so shall so modify the request or the procedures for handling data or information produced in response to the request.

30.6.2.3.3 If the ISO determines that the requested information has not or will not be provided within a reasonable time, the ISO may invoke the dispute resolution provisions of the ISO Services Tariff to determine the ISO's right to obtain the requested information. The parties may agree to submit any such determination to binding arbitration and may seek expedited resolution, in accordance with the applicable dispute resolution procedures. The ISO may initiate judicial or regulatory proceedings at any time to compel the production of the requested information.

30.6.3 Data Retention

30.6.3.1 Section 30.6.3 of Attachment O sets forth requirements for the retention of market information by the ISO, by the Market Monitoring Unit and by Market

Parties. The provisions of this data retention policy are binding on the ISO, on the Market Monitoring Unit and on Market Parties.

30.6.3.2 Except as specified herein, a Market Party shall retain the data and information specified in Section 30.6.2.2 of Attachment O for a period of six years from the date to which the data relates.

30.6.3.3 The ISO or its Market Monitoring Unit (as appropriate) shall retain for a period of six years from the date to which the data or information relates:

30.6.3.3.1 data or information required to be submitted to, or otherwise used by, the ISO in connection with the bidding, scheduling and dispatch of resources or loads in the New York energy, ancillary services, TCC or Installed Capacity (ICAP) markets;

30.6.3.3.2 data or information used or monitored by the ISO on system conditions in the New York Control Area, including but not limited to transmission constraints or planned or forced facility outages, that materially affect transmission congestion costs or market conditions in the New York energy, ancillary services or ICAP markets;

30.6.3.3.3 data or information collected by the ISO or by the Market Monitoring Unit (as appropriate) in the course of their implementation of Attachment O or the Market Mitigation Measures, on conditions in markets external to New York, or on fuel prices or other economic conditions that materially affect market conditions in the New York energy, ancillary services, TCC or ICAP markets;

30.6.3.3.4 data or information relating to the imposition of, or a decision not to impose, mitigation measures; and

30.6.3.3.5 such other data or information as the MMA or Market Monitoring Unit deem it necessary to collect in order to implement Attachment O or the Market Mitigation Measures.

30.6.3.4 The foregoing obligations to retain data or information shall not alter any data retention requirements that may otherwise be applicable to the ISO, to the Market Monitoring Unit, or to a Market Party; nor shall any such other data retention requirement alter the requirements specified above.

30.6.3.5 The ISO, Market Monitoring Unit or a Market Party may, at its option, purge or otherwise destroy any data or information that has been retained for the longest applicable period specified above, provided the retention of such data or information is not mandated by the FERC, the New York Public Service Commission, or other applicable requirement or obligation.

30.6.3.6 Compliance with the requirements specified herein for the retention of data or information shall not suspend or waive any statute of limitations or doctrine of laches, estoppel or waiver that may be applicable to any claim asserted against the ISO, the Market Monitoring Unit, or a Market Party.

30.6.4 Confidentiality

The Market Monitoring Unit and the ISO shall use all reasonable procedures necessary to protect and preserve the confidentiality of Protected Information, provided that such information is not available from public sources, is not otherwise subject to disclosure under any tariff or agreement administered by the ISO, and is properly designated as Protected Information. The ISO and the Market Monitoring Unit's obligation to protect and preserve the confidentiality of

Protected Information shall be of a continuing nature, and shall survive the rescission, termination or expiration of this Plan.

Except as may be required by subpoena or other compulsory process, or as authorized in the ISO's Tariffs and governing documents (including this Plan), the Market Monitoring Unit and the ISO shall not disclose Protected Information to any person or entity without the prior written consent of the party that the Protected Information pertains to. Upon receipt of a subpoena or other compulsory process for the disclosure of Protected Information, the ISO and/or the Market Monitoring Unit shall promptly notify the party that the Protected Information pertains to, and shall provide all reasonable assistance requested by the party to prevent or limit disclosure. Upon receipt of a subpoena or other compulsory process for the disclosure of Protected Information that was provided to the ISO or the Market Monitoring Unit pursuant to Section 30.6.6 below, the ISO or the Market Monitoring Unit, as appropriate, shall promptly notify the entity that provided the Protected Information and shall provide all reasonable assistance requested by that party to prevent or limit disclosure. Nothing in this Plan alters any existing statutory jurisdiction or authority to compel disclosure that may apply to the ISO, its Market Monitoring Unit, or to any other ISO, RTO, or market monitoring unit.

The ISO may, in consultation with the Market Monitoring Unit, adopt further or different procedures for the designation of information as Protected Information, or for the reasonable protection of Protected Information, after providing an opportunity for interested parties to review and comment on such procedures; provided, however, that such further or different procedures shall not permit the ISO or Market Monitoring Unit to disclose data or information that would be protected from disclosure under the procedures in place at the time the data or information was provided to the ISO or to the Market Monitoring Unit.

30.6.5 Collection and Availability of Information

30.6.5.1 The ISO and the Market Monitoring Unit shall regularly collect and maintain the information necessary for implementing Attachment O.

The ISO and the Market Monitoring Unit may provide Protected Information to each other as they determine necessary to carry out the purposes of this Plan.

30.6.5.2 The ISO, in consultation with the Market Monitoring Unit, shall make publicly available: (i) a description of the categories of data and information collected and maintained by the MMA and Market Monitoring Unit; (ii) such data or information as may be useful for the competitive or efficient functioning of any of the New York Electric Markets that can be made publicly available consistent with the confidentiality of Protected Information; and (iii) if and to the extent consistent with confidentiality requirements, such summaries, redactions, abstractions or other non-confidential compilations, versions or reports of Protected Information as may be useful for the competitive or efficient functioning of any of the New York Electric Markets. Any such proposed methods for creating non-confidential reports of such information shall only be adopted after provision of a reasonable opportunity for, and consideration of, the comments of Market Parties and other interested parties. All such proposed or adopted methods shall be set forth in the ISO Procedures, shall be made available through the ISO web site or comparable means, and shall be subject to review and approval by the Board.

30.6.5.3 Consistent with the foregoing requirements, the ISO and its Market Monitoring Unit shall make available, through the ISO web site or comparable

means, such reports on the New York Electric Markets as they determine will, at reasonable cost, facilitate competition in those markets.

30.6.5.4 Any data or other information collected by the ISO relating to any of the New York Electric Markets shall be provided upon request, and without undue discrimination between requests, to a Market Party, other interested party, or an Interested Government Agency, provided: (i) such data or information is not Protected Information, or the party designating it as Protected Information has consented in writing to its disclosure; (ii) such information can be provided without undue burden or disruption to, or interference with the other duties and responsibilities of the ISO; and (iii) the requesting party, if other than an Interested Government Agency, provides appropriate guarantees of reimbursement of the costs to the ISO of compiling and disclosing the data or information. If the ISO determines that doing so would not be unduly burdensome or expensive, or inconsistent with maintaining the competitiveness or economic efficiency of any market, the ISO shall make data or information provided in accordance with this paragraph available to interested parties through the ISO web site or other appropriate means.

30.6.5.5 The New York Public Service Commission and any Other State Commission may make tailored requests to the Market Monitoring Unit for information related to general market trends and the performance of the New York Electric Markets. If the Market Monitoring Unit determines that such a request is not unduly burdensome, it shall provide the information sought, subject

to the restrictions and limitations established in Sections 30.6.5.5.1, 30.6.5.5.2 and 30.6.5.5.4, below.

30.6.5.5.1 Except as provided in this Section 30.6.5.5.1, the Market Monitoring Unit shall not provide Protected Information to the New York Public Service Commission or to an Other State Commission in response to a request under Section 30.6.5.5 above. The Market Monitoring Unit may, but is not required to, provide Protected Information to the New York Public Service Commission or any Other State Commission when the party to which the requested Protected Information pertains has consented in writing to its disclosure. The Market Monitoring Unit may, but is not required to, provide Protected Information to the New York Public Service Commission or an Other State Commission if the general counsel/chief legal officer of the requesting state commission certifies, in writing, that: (i) the requested Protected Information will be protected from disclosure by law (and provides copies of the relevant laws, rules or regulations under which the requested Protected Information is protected from public disclosure); (ii) the requested Protected Information will be treated as confidential to the fullest extent of the laws of its state; (iii) the state commission will promptly notify the Market Monitoring Unit if it receives a request for disclosure of all or part of the Protected (iv) the state commission agrees to provide all reasonable and permissible assistance to prevent further disclosure of Protected Information provided by the Market Monitoring Unit to the state commission in response to a request governed by Section 30.6.5.5 of this Plan; and (v) the Protected Information will not be used for a state enforcement action.

The Market Monitoring Unit shall not provide Protected Information it received from another ISO or RTO, or from a market monitoring unit for another ISO or RTO, pursuant to the authority to share information granted by Section 30.6.6 of this Plan, in response to a request under Section 30.6.5.5 of this Plan. Instead, the Market Monitoring Unit shall identify to the requesting state commission the ISO, RTO or market monitoring unit that provided the information to the Market Monitoring Unit, so that the New York Public Service Commission or Other State Commission may request the Protected Information directly from its source in accordance with the provisions of the providing entity's tariffs, other governing documents, or an applicable law or rule.

30.6.5.5.2 Prior to disclosing Protected Information pertaining to a particular Market Party in response to a tailored request made under Section 30.6.5.5, the Market Monitoring Unit shall (1) notify the Market Party or Parties to which the Protected Information pertains of the request and describe the information that the Market Monitoring Unit proposes to disclose, and (2) allow the Market Party or Parties a reasonable time to object to the disclosure and to provide context to the Protected Information related to it. Providing the opportunity for Market Parties to object to disclosure, or to provide context to the information being produced shall not be permitted to unduly delay its release.

30.6.5.5.3 Section 30.6.5.5 of Attachment O pertains to requests by the New York Public Service Commission and Other State Commissions to the Market Monitoring Unit to provide information. Section 30.6.4 of Attachment O

addresses how the Market Monitoring Unit responds to compulsory processes, such as subpoenas and court orders.

30.6.5.5.4 In responding to a request under Section 30.6.5.5 of Attachment O, the Market Monitoring Unit shall not knowingly provide information to the New York Public Service Commission, or to any Other State Commission, that is designed to aid a state enforcement action.

30.6.5.5.5 The New York Public Service Commission or any Other State Commission may petition FERC to require the ISO to release information that the Market Monitoring Unit is not required to release, or that the Market Monitoring Unit is proscribed from releasing, under this Section 30.6.5.5 of Attachment O.

30.6.5.6 The Market Monitoring Unit shall respond to information and data requests issued to it by the Commission or its staff. If the Commission or its staff, during the course of an investigation or otherwise, requests Protected Information from the Market Monitoring Unit that is otherwise required to be maintained in confidence, the Market Monitoring Unit shall provide the requested information to the Commission or its staff within the time provided for in the request for information. In providing the information to the FERC or its staff, the Market Monitoring Unit shall, consistent with any FERC rules or regulations that may provide for privileged treatment of that information, request that the information be treated as confidential and non-public by the FERC and its staff and that the information be withheld from public disclosure. The Market Monitoring Unit shall not be held liable for any losses, consequential or otherwise, resulting from the Market Monitoring Unit divulging such Protected Information pursuant to a

request under this Section 30.6.5.6. After the Protected Information has been provided to the Commission or its staff, the Market Monitoring Unit shall immediately notify any affected Market Participant(s) when it becomes aware that a request for disclosure of such Protected Information has been received by the Commission or its staff, or a decision to disclose such Protected Information has been made by the Commission, at which time the Market Monitoring Unit and the affected Market Participant(s) may respond before such information would be made public, pursuant to the Commission's rules and regulations that may provide for privileged treatment of information provided to the Commission or its staff.

30.6.6 Sharing Information with Other ISOs/RTOs and Market Monitoring Units

30.6.6.1 The Market Monitoring Unit or the ISO may disclose Protected Information to another ISO or RTO or to another ISO or RTO's market monitoring unit (each a "Requesting Entity" in Section 30.6.6 of the Plan) if the Requesting Entity submits a written request stating that the requested Protected Information is necessary to an investigation or evaluation that the Requesting Entity is undertaking within the scope of its approved tariffs, other governing documents, or an applicable law or rule to determine (a) if market power is being, or has been, exercised, (b) if market manipulation is occurring or has occurred, or (c) if a market design flaw exists between interconnected markets, and either (i) demonstrates (by providing copies of the relevant documents, provisions, statutes, rules, orders, etc.) that its tariff or other governing document limits further disclosure of the Protected Information in a manner that satisfies all of the requirements set forth in Section 30.6.6.1.1, below, or (ii) executes a non-

disclosure agreement with the ISO and/or the Market Monitoring Unit that incorporates all of the requirements set forth in Section 30.6.6.1.1 below, and provides a written certification that the Requesting Entity possesses legal authority to enter into the required non-disclosure agreement and to be bound by its terms.

30.6.6.1.1 The Requesting Entity's governing documents or non-disclosure agreement must:

- (1) protect Protected Information that the ISO or the Market Monitoring Unit provides from disclosure, except where disclosure may be required by the FERC or by subpoena or other compulsory process;
- (2) establish a legally enforceable obligation to treat Protected Information provided by the ISO or its Market Monitoring Unit as confidential. Such obligation must be of a continuing nature, and must survive the rescission, termination or expiration of the applicable tariff(s), other governing document(s) or non-disclosure agreement;
- (3) require state commissions to request Protected Information provided by the ISO or its Market Monitoring Unit directly from the ISO or its Market Monitoring Unit, in a manner consistent with Section 30.6.5.5.1 of this Plan, and promptly inform the ISO or its Market Monitoring Unit of any requests received from a state commission for Protected Information provided by the ISO or its Market Monitoring Unit;
- (4) require the Requesting Entity to promptly notify the ISO or its Market Monitoring Unit and seek appropriate relief to prevent or, if it is not possible to prevent, to

limit disclosure in the event that a subpoena or other compulsory process seeks to require disclosure of Protected Information provided by the ISO or its Market Monitoring Unit;

- (5) require the Requesting Entity to promptly notify the ISO or its Market Monitoring Unit of any third party requests for additional disclosure of the Protected Information where Protected Information provided by the ISO or its Market Monitoring Unit has been disclosed to a court or regulatory body in response to a subpoena or other compulsory process, and to seek appropriate relief to prevent or limit further disclosure; and
- (6) require the destruction of the Protected Information at the earlier of (i) five business days after a request from the ISO or its Market Monitoring Unit for the return of the Protected Information is received, or (ii) the conclusion or resolution of the investigation or evaluation.

30.6.6.2 The ISO or the Market Monitoring Unit may undertake a joint investigation with another ISO/RTO or with another ISO or RTO's market monitoring unit to determine (a) if market power is being, or has been, exercised, (b) if market manipulation is occurring or has occurred, or (c) if a market design flaw exists in or between interconnected markets. In such a case, the ISO and the Market Monitoring Unit may disclose Protected Information to the other ISO/RTO or market monitoring unit as necessary to achieve the objectives of the investigation; provided that the ISO or Market Monitoring Unit first receives a written certification from the other ISO/RTO or market monitoring unit that its tariffs or other governing documents meet the standards set forth in this Section

30.6.6 or executes a non-disclosure agreement.

30.6.6.3 If the ISO discloses Protected Information to a Requesting Entity that is a jurisdictional ISO or RTO, the ISO shall also provide the Protected Information to the Requesting Entity's market monitoring unit as soon as the Requesting Entity's market monitoring unit satisfies the requirements of Section 30.6.6.1.1, above.

30.6.6.4 Protected Information provided by another ISO/RTO or market monitoring unit to the ISO or to the Market Monitoring Unit pursuant to the provisions of this Plan shall either be destroyed or returned to the entity that provided the Protected Information at the earlier of (i) five business days after receipt of a request from that entity for the return of the Protected, or (ii) the conclusion or resolution of the matter being investigated.