NYISO MST

New York Independent System Operator, Inc.
NYISO MST

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New York Independent System Operator, Inc.
Market Administration and Control Area Services Tariff

1 Introduction and Purpose

The New York Independent System Operator Market Administration and Control Area Services Tariff (the "ISO Services Tariff" or the "Tariff") sets forth the provisions applicable to the services provided by the ISO related to its administration of competitive markets for the sale and purchase of Energy and Capacity and for the payments to Suppliers who provide Ancillary Services to the ISO in the ISO Administered Markets ("Market Services") and the ISO's provision of Control Area Services ("Control Area Services"), including services related to ensuring the reliable operation of the NYS Power System. The Tariff addresses the Market Services and the Control Area Services provided by the New York ISO, and the terms and conditions under which those services are provided. Market Services are addressed in Article 4 of the Tariff, and Control Area Services are addressed in Article 5 of the Tariff. Transmission Service is provided under the ISO's Open Access Transmission Tariff (the "ISO OATT"). All references to Sections, Schedules and Attachments, unless otherwise noted, are references to the ISO Services Tariff.

2 DEFINITIONS

The following definitions are applicable to the ISO Services Tariff:

2.1 Definitions - A

Actual Demand Reductions: Demand Reductions that are measured using a revenue-quality real-time meter.

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

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

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

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

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

Adjusted Installed Capacity: The amount of installed Capacity a Resource may offer taking into account the Resource's applicable Capacity Accreditation Factor.

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

Access Transmission Tariff and set forth in a separate service schedule under the PJM Interconnection, L.L.C. Open Access Transmission Tariff; or (4) A right to schedule transmission service over the HTP Scheduled Line that is obtained in accordance with the rules and procedures established pursuant to Section 38 of the PJM Interconnection, L.L.C. Open Access Transmission Tariff and set forth in a separate service schedule under the PJM Interconnection, L.L.C. Open Access Transmission Tariff.

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

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

Aggregation: A Resource, comprised of two or more individual Generators, Demand Side Resources, or Distributed Energy Resources, or one or more individual Demand Side Resources, at separate points of interconnection and that are grouped and dispatched as a single unit by the ISO, and for which Energy injections, withdrawals and Demand Reductions are modeled at a single Transmission Node. *See*, Services Tariff Sec. 4.1.10.

Aggregator: A Supplier that offers Capacity, Energy, and/or Ancillary Services for an Aggregation.

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

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

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

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

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

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

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

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

2.2 Definitions - B

Back-Up Operation: The procedures for operating the NYCA in a safe and reliable manner when the ISO's normal communication or computer systems are not fully functional as set forth in Section 5.3 of this ISO Services Tariff and Article 2.12 of the ISO OATT.

Balance-of-Period Auction: As defined in the ISO OATT.

Base Point Signals: Electronic signals sent from the ISO and ultimately received by Generators or Aggregations specifying the scheduled MW setpoint for the Generator or Aggregation. Real-Time Dispatch ("RTD") Base Point Signals are typically sent to Generators or Aggregations on a nominal five (5) minute basis. AGC Base Point Signals are typically sent to Generators or Aggregations on a nominal six (6) second basis.

Basis Amount: The amount owed to the ISO for purchases of Energy and Ancillary Services excluding External Transactions in the Basis Month, after applying the Price Adjustment, as further adjusted by the ISO to reflect material changes in the extent of the Customer's participation in the ISO-administered Energy and Ancillary Services markets.

Basis Month: The month during the Prior Equivalent Capability Period in which the amount owed by the Customer for purchases of Energy and Ancillary Services excluding External Transactions, after applying the Price Adjustment, was greatest.

Beginning Energy Level: For Energy Storage Resources or Aggregations comprised entirely of Energy Storage Resources, the total amount of Energy stored by the Resource at the beginning of a market interval. The Beginning Energy Level shall be estimated for the Day-Ahead Market. An ISO-Managed Energy Storage Resource or ISO-Managed Aggregation comprised entirely of Energy Storage Resources shall submit an estimated Beginning Energy Level on each day that it submits a Day-Ahead Market Bid. The Beginning Energy Level shall be determined by 6-second telemetry data in real-time. If the ISO does not receive real-time telemetry from the Resource due to equipment failure or other reason, the ISO will use the last valid Energy Level value as modified to reflect subsequent schedules.

Behind-the-Meter Net Generation Resource ("BTM:NG Resource"): A facility within a defined electrical boundary comprised of a Generator and a Host Load located at a single point identifier (PTID), where the Generator routinely serves, and is assigned to, the Host Load and has excess generation capability after serving that Host Load. The Generator of the BTM:NG Resource must be electrically located in the NYCA, have a minimum nameplate rating of 2 MW and a minimum net injection to the NYS Transmission System or distribution system of 1 MW. The Host Load of the BTM:NG Resource must also have a minimum ACHL of 1 MW. A facility that otherwise meets these eligibility requirements, but either (i) is an Intermittent Power Resource or Energy Storage Resource, (ii) whose Host Load consists only of Station Power, or (iii) has made an election pursuant to Section 5.12.1.12, does not qualify to be a BTM:NG Resource. BTM:NG Resources cannot simultaneously participate as a BTM:NG Resource and in any ISO administered demand response programs.

Bid/Post System: An electronic information system used to allow the posting of proposed transmission schedules and Bids for Energy and Ancillary Services by Market Participants for use by the ISO and to allow the ISO to post LBMPs and schedules.

Bid: Offer to sell or bid to purchase Energy, Demand Reductions or Transmission Congestion Contracts and an offer to sell Ancillary Services at a specified price that is duly submitted to the ISO pursuant to ISO Procedures. Bid shall mean a mitigated Bid where appropriate.

Bid Price: The price at which the Customer offering the Bid is willing to provide the product or service, or is willing to pay to receive such product or service, as applicable. In the case of a CTS Interface Bid, the Bid Price is a dollar value that indicates the bidder's willingness to purchase Energy at a CTS Source and sell it at a CTS Sink across a CTS Enabled Interface if, at the time of scheduling, the forecasted CTS Sink Price minus the forecasted CTS Source Price is greater than, or equal to, the dollar value specified in the Bid.

Bid Production Cost: Total cost of the Generators and Aggregations required to meet Load and reliability Constraints based upon Bids corresponding to the usual measures of Generator or Aggregation production cost (e.g., running cost, Minimum Generation Bid, and Start-Up Bid).

Bidder: An entity that bids to purchase Unforced Capacity in an Installed Capacity auction.

Bidding Requirement: The credit requirement for bidding in certain ISO-administered auctions, calculated in accordance with Section 26.4.3 of Attachment K to this Services Tariff.

Bilateral Transaction: A Transaction between two or more parties for the purchase and/or sale of Capacity or Energy other than those in the ISO Administered Markets. A request to schedule a Bilateral Transaction in the Energy Market shall be considered a request to schedule Point-to-Point Transmission Service.

Billing Period: The period of time designated in Sections 7.2.2.1, 7.2.3.1, or 7.2.3.2 of this ISO Services Tariff over which the ISO will aggregate and settle a charge or a payment for services furnished under this ISO Services Tariff or the ISO OATT.

2.3 Definitions - C

Capability Period: Six-month periods which are established as follows: (i) from May 1 through October 31 of each year ("Summer Capability Period"); and (ii) from November 1 of each year through April 30 of the following year ("Winter Capability Period").

Capability Period Auction: An auction conducted no later than thirty (30) days prior to the start of each Capability Period in which Unforced Capacity may be purchased and sold in a six-month strip.

Capability Period SCR Load Zone Peak Hours: The top forty (40) coincident peak hours that, prior to the Summer 2014 Capability Period include hour beginning thirteen through hour beginning eighteen and beginning with the Summer 2014 Capability Period include hour beginning eleven through hour beginning nineteen. The Capability Period SCR Load Zone Peak Hours shall be determined by the NYISO from the Prior Equivalent Capability Period and shall be used by RIPs to report ACL values for the purpose of SCR enrollment. For a SCR enrolled with a Provisional ACL that requires verification data to be reported at the end of the Capability Period in which the SCR was enrolled, the Capability Period SCR Load Zone Peak Hours shall be determined from the Capability Period in which the SCR was enrolled. Such hours shall not include (i) hours in which Special Case Resources located in the specific Load Zone were called by the ISO to respond to a reliability event or test and (ii) hours for which the Emergency Demand Response Program resources were deployed by the ISO in each specific Load Zone. In addition, beginning with the Summer 2014 Capability Period, the NYISO shall not include, in descending rank order of NYCA Load up to a maximum of eight hours per Capability Period, a) the hour before the start time of a reliability event or performance test, in which SCRs located in the specific Load Zone were called by the ISO to respond to a reliability event or performance test, or b) the hour immediately following the end time of such reliability event or performance test.

Capability Year: A Summer Capability Period, followed by a Winter Capability Period (*i.e.,* May 1 through April 30).

Capacity: The capability to generate or transmit electrical power, or the ability to control demand at the direction of the ISO, measured in megawatts ("MW").

Capacity Accreditation Factor: Subject to Section 5.11.7 of this ISO Services Tariff, the factors, set annually by the ISO in accordance with Section 5.12.14.3 and ISO Procedures, that reflect the marginal reliability contribution of the ICAP Suppliers within each Capacity Accreditation Resource Class toward meeting NYSRC resource adequacy requirements for the upcoming Capability Year. Capacity Accreditation Factors for each Capacity Accreditation Resource Class will be determined by the ISO for Rest of State, G-J Locality (excluding Load Zone J), NYC Locality, and Long Island Locality, in accordance with Section 5.12.14.3 and ISO Procedures. Capacity Accreditation Factors are applicable to all Resources and/or Aggregations within each Capacity Accreditation Resource Class that has been established in accordance with ISO Procedures.

Capacity Accreditation Resource Class: A defined set of Resources and/or Aggregations, as identified in accordance with ISO Procedures, with similar technologies and/or operating characteristics which are expected to have similar marginal reliability contributions toward meeting NYSRC resource adequacy requirements for the upcoming Capability Year. Subject to Section 5.11.7 of this ISO Services Tariff, each Capacity Accreditation Resource Class will be evaluated through the annual review detailed in Section 5.12.14.3. Each Installed Capacity Supplier will be assigned a Capacity Accreditation Resource Class.

Capacity Limited Resource: Prior to May 1, 2025, a Resource that is constrained in its ability to supply Energy above its Normal Upper Operating Limit by operational or plant configuration characteristics became a Capacity Limited Resource by registering its Capacity limiting characteristics with, and justify them to, the ISO consistent with ISO Procedures. Prior to May 1, 2025, Capacity Limited Resources may submit a schedule indicating that their Normal Upper Operating Limit is a function depending on one or more variables, such as temperature or pondage levels, in which case the Normal Upper Operating Limit applicable at any time shall be determined by reference to that schedule. After April 30, 2025, Resources shall no longer be able to able to participate as Capacity Limited Resources in the Installed Capacity Market.

Capacity Reservation Cap: As defined in the ISO OATT.

CARL Data: Control Area Resource and Load ("CARL") data submitted by Control Area System Resources to the ISO.

Centralized Transmission Congestion Contracts ("TCC") Auction ("Auction"): As defined in the ISO OATT.

Champlain Hudson Power Express Merchant Transmission Facility ("CHPE MTF"): A transmission facility that interconnects the NYCA at Astoria Annex in Queens, New York to the Hydro-Québec Control Area at Hertel, La Prairie, Québec.

Co-located Storage Resources ("CSR"): An Energy Storage Resource and one other type of Generator that is not a Withdrawal-Eligible Generator. The second participating Generator can be a wind, solar, or landfill gas fueled Intermittent Power Resource, a Limited Control Run-of-River Hydro Resource, or a Dispatchable Generator which may require commitment and time to start-up. The two Generators must: (a) both be located behind a single Point of Injection (as defined in Section 1.16 of the OATT); (b) participate in the ISO Administered Markets as two distinct Generators; and (c) share a set of CSR Scheduling Limits. Generators that may not participate in the ISO-Administered Markets as components of a CSR include: (a) Limited Energy Storage Resources, (b) a Generator comprised of a group of generating units at a single location, which grouped generating units are separately committed and dispatched by the ISO, and for which Energy injections are measured at a single location, (c) Generators participating via a model that can accommodate several participants, including but not limited to Hybrid Storage Resources and Aggregations, and (d) Generators that serve a Host Load.

Code of Conduct: The rules, procedures and restrictions concerning the conduct of the ISO directors and employees, contained in Attachment F to the ISO Open Access Transmission Tariff.

Combined Cycle Gas Turbine ("CCGT") Generator: A Generator that produces electric power from gas turbine(s) and uses exhaust heat from gas turbine(s) to generate steam and additional electric power with a heat recovery steam generator and steam turbine(s).

Combined Cycle Gas Turbine ("CCGT") Generator with Duct-Firing Capability: A Combined Cycle Gas Turbine Generator equipped with duct burners, which add additional heat to the steam used to produce additional electric power from the heat recovery steam generator and steam turbine(s).

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

Commission ("FERC"): The Federal Energy Regulatory Commission, or any successor agency.

Compensable Overgeneration: A quantity of Energy provided over a given RTD interval in which a Supplier has offered Energy that exceeds the Real-Time Scheduled Energy established by the ISO for that Supplier and for which the Supplier may be paid pursuant to ISO Procedures.

For (i) Suppliers not covered by other provisions of this Section, (ii) Intermittent Power Resources depending on wind or solar energy as their fuel for which the ISO has imposed a Wind and Solar Output Limit in the given RTD interval, and (iii) Intermittent Power Resources depending on landfill gas as their fuel or Limited Control Run-of-River Hydroelectric Resources that participate as Co-located Storage Resources for which the ISO has imposed a Wind and Solar Output Limit in the given RTD interval, Compensable Overgeneration shall initially equal three percent (3%) of the Supplier's Normal Upper Operating Limit which may be modified by the ISO if necessary to maintain good Control Performance.

For a Generator or Aggregation: (i) which is operating in Start-Up or Shutdown Periods, or Testing Periods; or (ii) which is a Limited Control Run of River Hydro Resource that has offered its Energy to the ISO in a given interval not using the ISO-committed Flexible or Self-Committed Flexible bid mode (except as provided above); or (iii) which is an Intermittent Power Resource that depends on landfill gas for its fuel and has offered its Energy to the ISO in a given interval not using the ISO-committed Flexible or Self-Committed Flexible bid mode (except as provided above); or (iv) which is an Intermittent Power Resource that depends on wind or solar energy for its fuel (except as provided above), Compensable Overgeneration shall mean all Energy actually injected by the Generator or Aggregation that exceeds the Real-Time Scheduled Energy established by the ISO for that Generator or Aggregation.

For a Generator or Aggregation operating in intervals when it has been designated as operating Out of Merit at the request of a Transmission Owner or the ISO, Compensable Overgeneration shall mean all Energy actually provided by the Generator or Aggregation that exceeds the Real-Time Scheduled Energy up to the Energy level directed by the Transmission Owner or the ISO.

For a Generator comprised of a group of generating units at a single location, which grouped generating units are separately committed and dispatched by the ISO, and for which Energy injections are measured at a single location, Compensable Overgeneration shall mean that quantity of Energy injected by the Generator, during the period when one of its grouped generating units is operating in a Start-Up or Shutdown Period, that exceeds the Real-Time Scheduled Energy established by the ISO for that period, for that Generator, and for which the Generator may be paid pursuant to ISO Procedures.

Completed Application: An Application that satisfies all of the information and other requirements for service under the ISO Services Tariff.

Confidential Information: Information and/or data that has been designated by a Customer to be proprietary and confidential, provided that such designation is consistent with the ISO Procedures, the ISO Services Tariff, and the ISO Code of Conduct.

Congestion: A characteristic of the transmission system produced by a constraint on the optimum economic operation of the power system, such that the marginal price of Energy to serve the next increment of Load, exclusive of losses, at different locations on the transmission system is unequal.

Congestion Component: The component of the LBMP measured at a location or the Transmission Usage Charge between two locations that is attributable to the cost of transmission Congestion as is more completely defined in Attachment B of the Services Tariff.

Congestion Rent: As defined in the ISO OATT.

Congestion Rent Shortfall: As defined in the ISO OATT.

Constraint: An upper or lower limit placed on a variable or set of variables that are used by the ISO in its SCUC, RTC, or RTD programs to control and/or facilitate the operation of the NYS Transmission System.

Contingency: An actual or potential unexpected failure or outage of a system component, such as a Generator, transmission line, circuit breaker, switch or other electrical element. A Contingency also may include multiple components, which are related by situations leading to simultaneous component outages.

Control Area: An electric system or combination of electric power systems to which a common Automatic Generation Control scheme is applied in order to: (1) match, at all times, the power output of the Generators and Aggregations within the electric power system(s) and Capacity and Energy purchased from entities outside the electric power system(s), with the Load within the electric power system(s); (2) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice; (3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and (4) provide sufficient Capacity to maintain Operating Reserves in accordance with Good Utility Practice.

Control Area System Resource: A set of Resources owned or controlled by an entity within a Control Area that also is the operator of such Control Area. Entities supplying Unforced

Capacity using Control Area System Resources will not designate particular Resources as the suppliers of Unforced Capacity.

Control Performance: A standard for measuring the degree to which a Control Area is providing Regulation Service in conformance with NERC requirements.

Controllable Transmission: Any Transmission facility over which power-flow can be directly controlled by power-flow control devices without having to re-dispatch generation.

Credible Repair Plan: A Repair Plan that meets the requirements described in Section 5.18.1.4 of this Services Tariff and in ISO Procedures**.**

Credit Assessment: An assessment of a Customer's creditworthiness, conducted by the ISO in accordance with Section 26.5.3 of Attachment K to this Services Tariff.

Critical Electric System Infrastructure Load: Load that is critical to maintaining the reliable operation of electric system infrastructure, including, without limitation, Load that is (i) necessary to maintain the delivery of natural gas, fuel oil, and other fuels used by Generators (including Local Generators) to generate electricity, (ii) likely to impact the supply of natural gas, fuel oil, and other fuel to Generators, or (iii) otherwise likely to impact Generator operation. Critical Electric System Infrastructure Load does not include on-site Load that is consumed for ancillary purposes unless such Load is necessary for compliance with parts (i) – (iii) of this definition.

Cross-Sound Scheduled Line: A transmission facility that interconnects the NYCA to the New England Control Area at Shoreham, New York and terminates near New Haven, Connecticut.

CSR Scheduling Limits: The CSR injection Scheduling Limit is used to determine the combined Regulation Capacity, Operating Reserve and Energy injection schedules for, and the maximum permitted net injection by a CSR's Generators. The CSR withdrawal Scheduling Limit sets is used to determine the combined Regulation Capacity and Energy withdrawal schedules for, and the maximum permitted net withdrawal by a CSR's Generators.

The Market Participant that is responsible for submitting Bids for a set of CSR Generators shall submit a CSR injection Scheduling Limit and a CSR withdrawal Scheduling Limit with the hourly Day-Ahead and Real-Time Market Bids it submits for each of the CSR Generators. The CSR Scheduling Limit values that the Market Participant submits must reflect the physical capability to inject or withdraw Energy at the Point of Injection/Point of Withdrawal.

To address the real-time variability of Energy deliveries from the Intermittent Power Resource or Limited Control Run-of-River Hydro Resource that participate as Co-located Storage Resources, when the participating Energy Storage Resource has a non-zero Regulation and/or Operating Reserves schedule or is dispatched to inject Energy, and the sum of the participating Energy Storage Resource's and the participating Intermittent Power Resource's or Limited Control Run-of-River Hydro Resource's Energy, Regulation Service and Operating Reserves Schedules is greater than or equal to a specified percentage of the CSR injection Scheduling Limit, then the ISO will issue a Wind and Solar Output Limit to the Intermittent Power Resource or Limited

Control Run-of-River Hydro Resource to not exceed its Base Point Signal. The specified percentage that is ordinarily used will be posted on the ISO's website.

CTS Enabled Interface: An External Interface at which the ISO has authorized the use of Coordinated Transaction Scheduling ("CTS") market rules and which includes a CTS Enabled Proxy Generator Bus for New York and a CTS Enabled Proxy Generator Bus for the neighboring Control Area.

CTS Enabled Proxy Generator Bus: A Proxy Generator Bus at which the ISO either requires or permits the use of CTS Interface Bids for Import and Export Transactions in the Real-Time Market and requires the use of Decremental Bids for Wheels Through in the Real-Time Market. A CTS Enabled Proxy Generator Bus at which the ISO permits CTS Interface Bids will also permit Decremental and Sink Price Cap Bids.

CTS Interface Bid: A Real-Time Bid provided by an entity engaged in an External Transaction at a CTS Enabled Interface. CTS Interface Bids shall include a MW amount, a direction indicating whether the proposed Transaction is to Import Energy to, or Export Energy from, the New York Control Area, and a Bid Price.

CTS Sink: Representation of the location(s) within a Control Area where energy associated with a CTS Interface Bid is withdrawn. The NYCA CTS Sinks are Proxy Generator Buses.

CTS Sink Price: The price at a CTS Sink.

CTS Source: Representation of the location(s) within a Control Area where energy associated with a CTS Interface Bid is injected. The NYCA CTS Sources are Proxy Generator Buses.

CTS Source Price: The price at a CTS Source.

Curtailment or Curtail: A reduction in Transmission Service in response to a transmission Capacity shortage as a result of system reliability conditions.

Curtailment Services Provider: A qualified entity that can produce real-time, verified reductions in NYCA Load of at least 100 kW in a single Load Zone, pursuant to the Emergency Demand Response Program and related ISO procedures. The procedure for qualifying as a Curtailment Services Provider is set forth in Section 3 below and in ISO Procedures.

Curtailment Services Provider Capacity: Capacity from a Demand Side Resource nominated by a Curtailment Services Provider for participation in the Emergency Demand Response Program.

Customer: An entity which has complied with the requirements contained in the ISO Services Tariff, including having signed a Service Agreement, and is qualified to utilize the Market Services and the Control Area Services provided by the ISO under the ISO Services Tariff; provided, however, that a party taking services under the Tariff pursuant to an unsigned Service Agreement filed with the Commission by the ISO shall be deemed a Customer.

2.4 Definitions - D

Day-Ahead: Nominally, the twenty-four (24) hour period directly preceding the Dispatch Day, except when this period may be extended by the ISO to accommodate weekends and holidays.

Day-Ahead LBMP: The LBMPs calculated based upon the ISO's Day-Ahead Security Constrained Unit Commitment process.

Day-Ahead Margin: That portion of Day-Ahead LBMP, Operating Reserves settlement or Regulation Service settlement for an hour that represents the difference between the Supplier's accepted Day-Ahead offer price and the Day-Ahead LBMP, Operating Reserves settlement or Regulation Service settlement for that hour.

Day-Ahead Margin Assurance Payment: A supplemental payment made to an eligible Supplier that buys out of a Day-Ahead Energy, Regulation Service, or Operating Reserves schedule such that an hourly balancing payment obligation offsets its Day-Ahead Margin. Rules for calculating these payments, and for determining Suppliers' eligibility to receive them, are **set** forth in Attachment J to this ISO Services Tariff.

Day-Ahead Market: The ISO Administered Market in which Capacity, Energy and/or Ancillary Services are scheduled and sold Day-Ahead consisting of the Day-Ahead scheduling process, price calculations and Settlements.

Day-Ahead Reliability Unit: A Day-Ahead committed Resource which would not have been committed but for a request by a Transmission Owner to the ISO that the unit be committed in the Day-Ahead Market in order to meet the reliability needs of the Transmission Owner's local system or as the result of the ISO's analysis indicating the unit was needed in order to meet the reliability requirements of the NYCA.

Decremental Bid: A monotonically increasing Bid curve provided by an entity engaged in a Bilateral Import, other than an entity submitting a CTS Interface Bid, or Internal Transaction to indicate the LBMP below which that entity is willing to reduce its Generator's output, and purchase Energy in the LBMP Markets, or by an entity engaged in a Wheel Through Transaction to indicate the Congestion Component cost at or below which that entity is willing to accept Transmission Service.

Demand Reduction: A quantity of reduced electricity demand from a Demand Side Resource or a Distributed Energy Resource that is bid, produced, purchased or sold over a period of time and measured or calculated in Megawatt hours. Demand Reductions of Critical Electric System Infrastructure Load shall not be bid, produced, or sold, unless such Demand Reductions are facilitated by use of a Local Generator.

Demand Side Resource: A Resource located in the NYCA that: (i) is capable of controlling demand by either curtailing its Load or by operating a Local Generator to reduce Load from the NYS Transmission System and/or the distribution system at the direction of the ISO, in a responsive, measurable and verifiable manner within time limits, and (ii) is qualified to participate in competitive Energy, Capacity, Operating Reserves or Regulation Service markets,

or in the Emergency Demand Response Program pursuant to this ISO Services Tariff and the ISO Procedures.

Dennison Scheduled Line: A transmission facility that interconnects the NYCA to the Hydro Quebec Control Area at the Dennison substation, located near Massena, New York and extends through the province of Ontario, Canada (near the City of Cornwall) to the Cedars substation in Quebec, Canada.

Dependable Maximum Gross Capability ("DMGC"): The sustained maximum output of the Generator of a BTM:NG Resource, as demonstrated by the performance of a test or through actual operation in accordance with, and averaged over a continuous time period as defined in, ISO Procedures.

Dependable Maximum Net Capability ("DMNC"): The sustained maximum net output of a Generator, or, where appropriate, an Aggregation, as demonstrated by the performance of a test or through actual operation, averaged over a continuous time period as defined in the ISO Procedures.

DER Aggregation: An Aggregation consisting of one or more Demand Side Resources, or two or more different Resource types, as described in Section 4.1.10 of the Services Tariff.

Desired Net Interchange ("DNI"): A mechanism used to set and maintain the desired Energy interchange (or transfer) between two Control Areas; it is scheduled ahead of time and can be changed manually in real-time.

Direct Sale: As defined in the ISO OATT.

Dispatchable: A bidding mode in which Generators or Aggregations indicate that they are willing to respond to real-time control from the ISO. A Dispatchable Generator, not including the Generator of a BTM:NG Resource, may be either ISO-Committed Flexible or Self-Committed Flexible. A Dispatchable Generator that is the Generator serving a BTM:NG Resource must be Self-Committed Flexible. Dispatchable Resources that are not providing Regulation Service will follow five-minute RTD Base Point Signals. Dispatchable Resources that are providing Regulation Service will follow six-second AGC Base Point Signals.

Dispatch Day: The twenty-four (24) hour (or, if appropriate, the twenty-three (23) or twenty-five (25) hour) period commencing at the beginning of each day (0000 hour).

Dispute Resolution Administrator ("DRA"): An individual hired by the ISO to administer the Expedited Dispute Resolution Procedures in Section 5.17 of the ISO Services Tariff.

Distributed Energy Resource ("DER"): (i) a facility comprising two or more Resource types behind a single point of interconnection with an Injection Limit of 20 MW or less; or (ii) a Demand Side Resource; or (iii) a Generator with an Injection Limit of 20 MW or less, that is electrically located in the NYCA.

DMNC Test Period: The period within a Capability Period during which a Resource shall conduct a DMNC test, or a BTM:NG Resource shall conduct a DMGC test, if such a test is required. Such periods will be established pursuant to the ISO Procedures.

Duty Eligible Proxy Generator Bus: As defined in the ISO OATT.

Dynamically Scheduled Proxy Generator Bus: A Proxy Generator Bus for which the ISO may schedule Transactions at 5 minute intervals in real time. Dynamically Scheduled Proxy Generator Buses are identified in Section 4.4.4 of the Services Tariff.

2.5 Definitions - E

East of Central-East: An electrical area comprised of Load Zones F, G, H, I, J, and K, as identified in the ISO Procedures.

East of Central-East Excluding Long Island: An electrical area comprised of Load Zones F, G, H, I, and J, as identified in the ISO Procedures.

East of Central-East Excluding New York City and Long Island: An electrical area comprised of Load Zones F, G, H, and I, as identified in the ISO Procedures.

Economic Operating Point: The megawatt quantity which is a function of: i) the real-time LBMP at the Resource bus; and ii) the Supplier's real-time eleven constant cost step Energy Bid, for the Resource, such that (a) the offer price associated with Energy offers below that megawatt quantity (if that megawatt quantity is not that Resource's minimum output level) must be less than or equal to the real-time LBMP at the Resource bus, and (b) the offer price associated with Energy offers above that megawatt quantity (if that megawatt quantity is not that Resource's maximum output level) must be greater than or equal to the real-time LBMP at the Resource bus. In cases where multiple megawatt values meet conditions (a) and (b), the Economic Operating Point is the megawatt value meeting these conditions that is closest to the Resource's real-time scheduled Energy provided. In cases where the Economic Operating Point would be less than the minimum output level, the Economic Operating Point will be set equal to the MW value of the first point on the Energy Bid curve and in cases where the Economic Operating Point would be greater than the maximum output level, the Economic Operating Point will be set equal to the MW value of the last point on the Energy Bid curve. When evaluating the Economic Operating Point of a BTM:NG Resource, only Energy offers corresponding to quantities in excess of its Host Load will be considered.

Emergency: Any abnormal system condition that requires immediate automatic or manual action to prevent or limit loss of transmission facilities or Generators that could adversely affect the reliability of an electric system.

Emergency Demand Response Program ("EDRP"): A program pursuant to which the ISO makes payments to Curtailment Service Providers that voluntarily take effective steps in real time, pursuant to ISO procedures, to reduce NYCA demand in Emergency conditions.

Emergency State: The state that the NYS Power System is in when an abnormal condition occurs that requires automatic or immediate, manual action to prevent or limit loss of the NYS Transmission System or Generators that could adversely affect the reliability of the NYS Power System.

Emergency Upper Operating Limit (UOL_E): The upper operating limit that a Generator or an Aggregation, except for the Generator of a BTM:NG Resource, indicates it expects to be able to reach, or the upper operating limit that 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, at the request of the ISO during extraordinary conditions. Each Resource shall specify a UOL_E in its bids that shall be equal to or greater than its stated Normal Upper Operating Limit.

Energy ("MWh"): A quantity of electricity that is bid, produced, purchased, consumed, sold, or transmitted over a period of time, and measured or calculated in megawatt hours. Demand Reductions by Demand Side Resources and Distributed Energy Resources are considered Energy.

Energy and Ancillary Services Component: A component of the Operating Requirement, calculated in accordance with Section 26.4.2 of Attachment K to this Services Tariff.

Energy Duration Limitation: for a Resource that is not capable of providing Energy for twenty-four hours each day, the number of consecutive hours per day that a Resource elects and is obligated, pursuant to Services Tariff Sections 5.12.1 and 5.12.7, to (i) schedule a Bilateral Transaction; (ii) Bid Energy in the Day-Ahead Market; or (iii) notify the ISO of any outages in the Day-Ahead Market as an Installed Capacity Supplier for the ICAP Equivalent of UCAP sold, as identified in Section 5.12.14 of the ISO Services Tariff.

Energy Level: The amount of Energy stored in an Energy Storage Resource or in an Aggregation comprised entirely of Energy Storage Resources.

Energy Level Management: The method by which an Energy Storage Resource or Aggregation comprised entirely of Energy Storage Resources controls the amount of Energy stored in the Resource(s). Energy Storage Resources and Aggregations comprised entirely of Energy Storage Resources may choose to be Self-Managed or ISO-Managed in their Bid and may be referred to as, for example, an "ISO-Managed Energy Storage Resource" or a "Self-Managed Aggregation comprised entirely of Energy Storage Resources" in the ISO Tariffs.

Energy Limited Resource: Capacity resources, not including BTM:NG Resources, that, due to environmental restrictions on operations, cyclical requirements, such as the need to recharge or refill, or other non-economic reasons, are unable to operate continuously on a daily basis, but are able to operate for at least four consecutive hours each day. Energy Limited Resources must register their Energy limiting characteristics with, and justify them to, the ISO consistent with ISO Procedures. Resources that meet the qualifications to be an Energy Limited Resource, and choose to participate in the wholesale market as an Energy Limited Resource, are not subject to the rules applicable to Energy Storage Resources.

Energy Storage Resource ("ESR"): Generators that receive Energy from the grid at a specified location, and are capable of storing that Energy, for later injection back onto the grid at the same location. Resources that cannot inject Energy onto the grid cannot be Energy Storage Resources. In order to qualify for wholesale market participation, Energy Storage Resources must be able to inject at a rate of at least 0.1 MW for a period of at least one hour, except that Energy Storage Resources operating as part of an Aggregation need only be able to inject at a rate of at least 0.01 MW for a period of at least one hour. Energy Storage Resources are Withdrawal-Eligible Generators.

Equivalent Demand Forced Outage Rate: The portion of time a unit is in demand, but is unavailable due to forced outages.

Equivalency Rating: A rating determined by the ISO, at a Customer's request, based on the ISO's financial evaluation of an Unrated Customer that shall serve as the starting point of the

ISO's determination of an amount of Unsecured Credit to be granted to the Customer, if any, as provided in Table K-1 of Attachment K to this Services Tariff.

ETA Agent: As defined in the ISO OATT.

ETCNL TCC: As defined in the ISO OATT.

Excess Amount: The difference, if any, between the dollar amounts charged to purchasers of Unforced Capacity in an ISO–administered Unforced Capacity auction and the dollar amounts paid to sellers of Unforced Capacity in that ISO–administered Installed Capacity auction.

Excess Congestion Rents: As defined in the ISO OATT.

Existing Transmission Capacity for Native Load ("ETCNL"): As defined in the ISO OATT.

Existing Transmission Agreement ("ETA"): As defined in the ISO OATT.

Expected EDRP/SCR MW: The aggregate Load reduction (in MW) expected to be realized from EDRP and/or SCRs during the real-time intervals that the ISO has called upon EDRP and/or SCRs to provide Load reduction in a Scarcity Reserve Region, as determined based on the ISO's calculation of the historical performance of EDRP and SCRs. There will be separate values for voluntary and mandatory Load reductions. When determining the historical performance of SCRs, provision of Load reduction shall be deemed mandatory if the ISO has satisfied the notification requirements set forth in Section 5.12.11.1 of this ISO Services Tariff as it relates to the SCRs in the applicable Load Zone, otherwise provision of such Load reduction shall be deemed voluntary. When determining the historical performance of the EDRP, provision of Load reduction by EDRP shall be deemed voluntary.

Expected Load Reduction: For purposes of determining the Real-Time Locational Based Marginal Price, the reduction in Load expected to be realized in real-time from activation of the Emergency Demand Response Program and from Load reductions requested from Special Case Resources, as established pursuant to ISO Procedures.

Expedited Dispute Resolution Procedures: The dispute resolution procedures applicable to disputes arising out of the Installed Capacity provisions of this ISO Services Tariff (as set forth in Section 5.17) and the Customer settlements provisions of this ISO Services Tariff (as set forth in Section 7.4.3).

Export: A Bilateral Transaction or purchase from the LBMP Market where the Energy is delivered to an NYCA Interconnection with another Control Area.

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

External: An entity (*e.g.*, Supplier, Transmission Customer) or facility (e.g., Generator, Interface) located outside the Control Area being referenced or between two or more Control Areas. Where a specific Control Area is not referenced, the NYCA is the intended reference.

External-to-ROS Deliverability Rights ("EDRs"): Rights, as measured in MW, associated with incremental transfer capability (i) on a new or existing Scheduled Line over an External Interface, with a terminus in Rest of State, and (ii) that has CRIS obtained pursuant to Attachment S or HH of the OATT. When combined with qualified Unforced Capacity which is located in an External Control Area either by contract or ownership, and which is deliverable to the NYCA Interface with Rest of State over which it created the incremental transfer capability, EDRs allow such Unforced Capacity to be offered into the ISO-Administered Market.

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

External Transactions: Purchases, sales or exchanges of Energy, Capacity or Ancillary Services for which either the Point of Injection ("POI") or Point of Withdrawal ("POW") or both are located outside the NYCA (*i.e.*, Exports, Imports or Wheels Through).

2.6 Definitions - F

Facility Flow-Based Methodology: As defined in the ISO OATT.

Fast-Start Resource: A Generator that (1) submits Start-up Bids and/or Minimum Generation Bids in the Day-Ahead or Real-Time Markets, (2) can respond to instructions to start, synchronize to the NYS Power System and inject Energy within thirty (30) minutes, and (3) has a minimum run time of one hour or less. Fast-Start Resources include but are not limited to Fixed Block Units.

A Fast-Start Resource may be enhanced by an integrated battery component or the addition of a battery, so long as the battery is integrated into the Fast-Start Resource's control system. Such an enhancement may only be used to: (a) decrease start-up time, (b) increase ramp rate, (c) smooth ramp rate, and/or (d) enable the Fast-Start Resource to provide 10-Minute Non-Synchronized Reserve. An enhanced Fast-Start Resource that has not started-up and is not already fully synchronized to the NYS Power System is not eligible to provide Spinning Reserve. An enhanced Fast-Start Resource that is a Fixed Block Unit may not use its battery to add a flexible operating range. An enhanced Dispatchable Fast-Start Resource that has started-up and is fully synchronized to the NYS Power System is eligible to use its battery to supplement the Spinning Reserve it can provide, but must ensure the Spinning Reserves will be sustainable for at least one hour if they are converted to Energy. The battery may not be used to increase the Upper Operating Limit of the Fast-Start Resource. An enhanced Fast-Start Resource is not permitted to be a Withdrawal-Eligible Generator, nor may it use Station Power to charge its battery. Finally, except as set forth above, an enhanced Fast-Start Resource is subject to the same market participation rules and requirements as other Fast-Start Resources.

Federal Power Act ("FPA"): The Federal Power Act, as may be amended from time-to-time (See 16 U.S.C. § 796 et seq.).

Firm Point-To-Point Transmission Service: Transmission Service under this Tariff that is scheduled between specified Points of Receipt and Delivery pursuant to the ISO OATT. Firm Point-To-Point Transmission Service is service for which the Transmission Customer has agreed to pay the Congestion associated with its service. A Transmission Customer may fix the price of Congestion associated with its Firm Point-To-Point Transmission Service by acquiring sufficient TCCs with the same Points of Receipt and Delivery as its Transmission Service.

Firm Transmission Service: Transmission service requested by a Transmission Customer willing to pay Congestion Rent.

First Settlement: The process of establishing binding financial commitments on the part of Customers participating in the Day-Ahead Market based on Day-Ahead LBMP.

Fixed Block Unit: A Fast-Start Resource that, due to operational characteristics, can only be dispatched in one of two states: either turned completely off, or turned on and run at a fixed capacity level.

Fixed Price TCC: As defined in the ISO OATT.

Forced Outage: An unscheduled inability of a Market Participant's Generator to produce Energy that does not meet the notification criteria to be classified as a scheduled outage or de-rate as established in ISO Procedures. If the Forced Outage of a Generator starts on or after May 1, 2015, the Forced Outage will expire at the end of the month which contains the 180th day of its Forced Outage but may be extended if the Market Participant has Commenced Repair of its Generator.

2.7 Definitions - G

GADS Data: Data submitted to the NERC for collection into the NERC's Generating Availability Data System ("GADS").

Gap Solution: This term shall have the meaning given in Attachment Y to the OATT.

Generator: A facility, including the Generator of a BTM:NG Resource, capable of supplying Energy, Capacity and/or Ancillary Services that is accessible to the NYCA. A Generator comprised of a group of generating units at a single location, which grouped generating units are separately committed and dispatched by the ISO, and for which Energy injections are measured at a single location, and each unit within that group, shall be considered a Generator.

G-J Locality: The Locality comprised of Load Zones G, H, I, and J collectively.

Good Utility Practice: Any of the practices, methods or acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods or acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather to delineate acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act Section 215(a)(4).

Grandfathered Rights: As defined in the ISO OATT.

Grandfathered TCCs: As defined in the ISO OATT.

2.8 Definitions - H

Host Load: The Load that is electrically interconnected within the defined electrical boundary of a BTM:NG Resource that is routinely served by, and assigned to, the Generator of a BTM:NG Resource. Station Power will be included in the calculation of the BTM:NG Resource's Host Load if it is self-supplied by the Generator of the BTM:NG Resource, and it is not separately metered pursuant to Section 5.12.6.1.1 and ISO Procedures.

HTP Scheduled Line: A transmission facility that interconnects the NYCA to the PJM Interconnection, L.L.C. Control Area at the West 49th Street Substation, New York, New York and terminates in Ridgefield, New Jersey.

2.9 Definitions - I

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

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

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

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

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

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

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

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

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

Inactive Reserves: The outage state in which a Market Participant's Generator is unavailable to produce Energy for a limited period of time not to exceed six months, for reasons that are not equipment related, which state does not meet the criteria to be classified as any other outage

pursuant to the provisions of this Services Tariff or of ISO Procedures. A Generator in Inactive Reserves is ineligible to participate in the Installed Capacity market.

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

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

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

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

Incremental TCC: As defined in the ISO OATT.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

ISO-Committed Flexible: A bidding mode in which a Dispatchable Generator or Aggregation comprised entirely of Energy Storage Resources follows Base Point Signals and is committed by the ISO. BTM:NG Resources are not permitted to utilize the ISO-Committed Flexible bidding mode. Only Aggregations that are entirely comprised of Energy Storage Resources and Aggregations that depend solely on wind or solar energy as their fuel are permitted to utilize the ISO-Committed Flexible bidding mode.

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

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

ISO OATT: The ISO Open Access Transmission Tariff.

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

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

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

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

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

2.10 Definitions - J

2.11 Definitions - K

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.

Limiting Participation Flag: An Operating Reserve and Regulation Service participation option that a Combined Cycle Gas Turbine Generator with Duct-Firing Capability may utilize, subject to technical validation pursuant to ISO Procedures, to limit its 10- Minute Spinning Reserves and Regulation Service Schedules to the Participation Limit.

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 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 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. Self-Committed Fixed or Flexible Bids to inject Energy for Self-Managed Energy Storage Resources, Self-Managed Aggregations consisting entirely of Energy Storage Resources, and DER Aggregations may include a Lower Operating Limit that is 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.

2.13 Definitions - M

Major Emergency State: An Emergency accompanied by abnormal frequency, abnormal voltage and/or equipment overloads that create a serious risk that the reliability of the NYS Power System could be adversely affected.

Marginal Losses: The NYS Transmission System Real Power Losses associated with each additional MWh of consumption by Load, or each additional MWh transmitted under a Bilateral Transaction as measured at the Points of Withdrawal.

Marginal Losses Component: The component of LBMP at a bus that accounts for the Marginal Losses, as measured between that bus and the Reference Bus.

Market-Clearing Price: The price determined in an Installed Capacity auction for each ISO-defined Locality, the remainder of the NYCA and each adjacent External Control Area for which all offers to sell and bids to purchase Unforced Capacity are in equilibrium.

Market Mitigation and Analysis Department: A department, internal to the ISO, that is responsible for participating in the ISO's administration of its Tariffs. The Market Mitigation and Analysis Department's duties are described in Section 30.3 of the Market Monitoring Plan that is set forth in Attachment O to this Services Tariff.

Market Monitoring Unit: "Market Monitoring Unit" shall have the same meaning in this ISO Services Tariff as it has in the Market Monitoring Plan that is set forth in Attachment O to this Services Tariff.

Market Participant: An entity, excluding the ISO, that produces, transmits, sells, and/or purchase for resale Unforced Capacity, Energy or Ancillary Services in the Wholesale Market. Market Participants include: Transmission Customers under the ISO OATT, Customers under the ISO Services Tariff, Power Exchanges, Transmission Owners, Primary Holders, LSEs, Suppliers and their designated agents. Market Participants also include entities buying or selling TCCs.

Market Problem: An issue which requires notification to Market Participants, the Commission and the Market Monitoring Unit pursuant to Section 3.5.1 of this Services Tariff. It includes market design flaws, software implementation and modeling anomalies or errors, market data anomalies or errors, and economic inefficiencies that have a material effect on the ISO-administered markets or transmission service. The term does not include erroneous Energy or Ancillary Services prices (which are managed through procedures outlined in Attachment E to the Services Tariff) or erroneous customer settlements.

Market Services: Services provided by the ISO under the ISO Services Tariff related to the ISO Administered Markets for Energy, Capacity and Ancillary Services.

MCZ Import Constrained Locality: A Mitigated Capacity Zone that is also an Import Constrained Locality.

Member Systems: The eight Transmission Owners that comprised the membership of the New York Power Pool, which are: (1) Central Hudson Gas & Electric Corporation, (2) Consolidated Edison Company of New York, Inc., (3) New York State Electric & Gas Corporation, (4) Niagara Mohawk Power Corporation d/b/a National Grid, (5) Orange and Rockland Utilities, Inc., (6) Rochester Gas and Electric Corporation, (7) the Power Authority of the State of New York, and (8) Long Island Lighting Company d/b/a Long Island Power Authority.

Meter Services Entity ("MSE"): An entity registered with the ISO and authorized to provide metering and meter data services, as applicable, to an Aggregator, Responsible Interface Party, or Curtailment Service Provider.

Minimum Generation Bid: A two-parameter Bid that identifies the minimum operating level a Supplier requires to operate a Generator, and the payment a Supplier requires to operate its Generator at that level. If the Supplier is a BTM:NG Resource, LESR, Energy Storage Resource, or an Aggregation, it shall not submit a Minimum Generation Bid.

Minimum Generation Level: For purposes of describing the eligibility of ten minute Resources to be committed by the Real Time Dispatch for pricing purposes pursuant to the Services Tariff, Section 4.4.3.3, an upper bound, established by the ISO, on the physical minimum generation limits specified by ten minute Resources. Ten minute Resources with physical minimum generation limits that exceed this upper bound will not be committed by the Real Time Dispatch for pricing purposes. The ISO shall establish a Minimum Generation Level based on its evaluation of the extent to which it is meeting its reliability criteria including Control Performance. The Minimum Generation Level, in megawatts, and the ISO's rationale for that level, shall be made available through the ISO's website or comparable means. If the Supplier is a BTM:NG Resource, LESR, Energy Storage Resource, or Aggregation, it shall not submit a Minimum Generation Level.

Minimum Payment Nomination: An offer, submitted by a Responsible Interface Party, in dollars per Megawatt-hour and not to exceed $500 per Megawatt-hour, to reduce Load equal to the Installed Capacity Equivalent of the amount of Unforced Capacity a Special Case Resource is supplying to the NYCA.

Mitigated Capacity Zone: New York City and any Locality added to the definition of "Locality" accepted by the Commission on or after March 31, 2013.

Modified Wheeling Agreement ("MWA"): A Transmission Wheeling Agreement between Transmission Owners that was in existence at the time of ISO start-up, as amended and modified as described in Attachment K. Modified Wheeling Agreements are associated with Generators or power supply contracts existing at ISO start-up. All Modified Wheeling Agreements are listed in Attachment L, Table 1A, and are designated in the "Treatment" column of Table 1A, as "MWA".

Monthly Auction: An auction administered by the ISO pursuant to Section 5.13.3 of the ISO Services Tariff.

Monthly Average Coincident Load ("Monthly ACL"): Beginning with the Summer 2014 Capability Period, the Load value calculated for each month during a Capability Period

applicable to a Special Case Resource with a reported Incremental Average Coincident Load. The Monthly ACL is an average of the SCR's metered hourly Load that is supplied by the NYS Transmission System and/or the distribution system and reported for the Monthly SCR Load Zone Peak Hours applicable to such SCR. The calculation and verification data reporting requirements are provided in Section 5.12.11.1.5 of this Services Tariff and ISO Procedures. Any Load supported by generation produced from a Local Generator, other behind-the-meter generator, or other supply source located behind the meter operating during the Monthly SCR Zone Load Peak Hours may not be included in the metered Load values reported for the Monthly ACL.

Monthly Net Benefit Threshold: The price, in $/MWh, determined by the ISO pursuant to Section 4.5.7.1 of the ISO Services Tariff and ISO Procedures.

Monthly SCR Load Zone Peak Hours: Beginning with the Summer 2014 Capability Period, the top forty (40) coincident peak hours for each month within a Capability Period that include hour beginning eleven through hour beginning nineteen as identified by the ISO for each Load Zone; provided, however, that such hours shall not include (i) hours in which Special Case Resources located in the specific Load Zone were called by the ISO to respond to a reliability event or test, (ii) hours for which the Emergency Demand Response Program resources were deployed by the ISO in each specific Load Zone and (iii) in descending rank order of NYCA Load up to a maximum of eight hours per month, a) the hour before the start time of a reliability event or performance test, in which SCRs located in the specific Load Zone were called by the ISO to respond to a reliability event or performance test, or b) the hour immediately following the end time of such reliability event or performance test.

Mothball Outage: The outage state in which a Market Participant's Generator is voluntarily removed from service on or after May 1, 2015, with applicable prior notice, for reasons not related to equipment failure. A Generator in Mothball Outage is subject to the return-to-service provisions in Section 5.18.4 of this Services Tariff and is ineligible to participate in the Installed Capacity market.

MTF Reservation: A right to submit a Bid into the NYISO Day-Ahead and/or Real-Time Markets over the Champlain Hudson Power Express MTF that is obtained in accordance with the rules and procedures established pursuant to Attachment II to the ISO OATT. *See* ISO OATT Sections 41.1.8 and 41.3.1.

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.

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 Fixed or Flexible Bids for Self-Managed Energy Storage Resources, Self-Managed 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 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 Winter Installed Reserve Margin: Starting with the 2027-2028 Capability Year, the ratio of the amount of additional Installed Capacity required by the NYISO to the NYCA Peak Load Forecast for the upcoming Winter Capability Period, expressed as a decimal.

NYCA Minimum Installed Capacity Requirement: Prior to the 2027-2028 Capability Year, 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. Starting with the 2027-2028 Capability Year, the requirement established for each Capability Period of the upcoming Capability Year is calculated as follows: (i) for the Summer Capability Period, multiplying the NYCA Peak Load Forecast for the Summer Capability Period by the quantity one plus the NYCA Installed Reserve Margin; and (ii) for the Winter Capability Period, multiplying the NYCA Peak Load Forecast for the Winter Capability Period by the quantity one plus the NYCA Winter Installed Reserve Margin.

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

NYCA Peak Load Forecast: Prior to the 2027-2028 Capability Year, the NYISO calculation of the peak hourly demand condition for the design day occurring on a non-NERC 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. Starting with the 2027-2028 Capability Year, the NYISO calculation of the peak hourly demand condition for the design day occurring on a non-NERC holiday weekday in the applicable months of each Capability Period for the upcoming Capability Year, determined in accordance with Sections 5.10 and 5.11 of the Services Tariff and based upon the weather-adjusted Load for the hour during a non-NERC holiday weekday in July or August for the Summer Capability Period and in December, January, or February for the Winter Capability Period in which actual Load in the NYCA was highest for the applicable Capability Period.

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 this Article 4 and Rate Schedule 4 of this ISO Services Tariff, to satisfy the various Operating Reserves requirements, including locational requirements, established by the Reliability Rules and other applicable reliability standards. The basic Operating Reserves products that will be procured by the ISO on behalf of the market are classified as follows:

(1) Spinning Reserve: Operating Reserves provided by Generators and Aggregations that meet the eligibility criteria set forth in Rate Schedule 4 of this ISO Services Tariff, are already synchronized to the NYS Power System, and can respond to instructions to change their output level, or reduce their Energy usage, within ten (10) minutes. Generators utilizing inverter-based energy storage technology and that otherwise meet the eligibility criteria set forth in this ISO Services Tariff may provide Spinning Reserves. Spinning Reserves may not be provided 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 Aggregations comprised of one or more (i) generating units (unless each of the generating units use inverter-based energy storage technology) or (ii) 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 more than one generating unit 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; and

(3) 30-Minute Reserve: Synchronized Operating Reserves provided by Generators and Aggregations, except Behind-the-Meter Net Generation Resources that are comprised of more than one generating unit and dispatched as a single aggregate unit or Aggregations that are comprised of one or more (i) generating units (unless each of the generating units use inverter-based energy storage technology) or (ii) Demand Side Resource(s) 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); or non-synchronized Operating Reserves provided by Generators, Aggregations, or Behind-the-Meter Net Generation Resources that are comprised of more than one generating unit 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.

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

Operating Study Power Flow: A Power Flow analysis that is performed at least once before each Capability Period that is used to determine each Interface Transfer Capability for the Capability Period (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.

2.16 Definitions - P

Participation Limit: The maximum amount of Energy that a Combined Cycle Gas Turbine Generator with Duct-Firing Capability can produce without using its Duct-Firing Capability, which is used as the upper limit for scheduling 10-min Spinning Reserves and Regulation Service. This limit does not apply to Energy scheduling.

Peak Load Window: The time period during which a Resource with Energy Duration Limitations must offer Energy in the Day-Ahead Market as specified in Section 5.12.14 of the ISO's Services Tariff.

Performance Index: An index, described in ISO Procedures, that tracks a Generator's or an Aggregation's response to AGC signals from the ISO.

Performance Tracking System: A system designed to report metrics for Generators, Aggregations, and Loads which include but are not limited to actual output and schedules. This system is used by the ISO to measure compliance with criteria associated with the provision of Energy and Ancillary Services.

Point-to-Point Transmission Service: The reservation and transmission of Capacity and Energy on a firm basis from the Point(s) of Receipt to the Point(s) of Delivery under the ISO Tariffs.

Point(s) of Delivery: Point(s) on the NYS Transmission System or Proxy Generator Buses where Energy transmitted by the ISO will be made available to the Transmission Customer under the OATT. The Point(s) of Delivery shall be specified pursuant to ISO Procedures.

Point(s) of Injection ("POI" or "Point of Receipt"): The point(s) on the NYS Transmission System or Proxy Generator Buses where Energy, Capacity and Ancillary Services will be made available to the ISO by the delivering party under the ISO OATT or the ISO Services Tariff. (May be referred to as "Point of Receipt" or similar in some Existing Transmission Agreements.)

Point(s) of Receipt: Point(s) of interconnection on the NYS Transmission System or Proxy Generator Buses where Energy will be made available to the ISO by the Transmission Customer under the OATT. The Point(s) of Receipt shall be specified pursuant to ISO Procedures.

Point(s) of Withdrawal ("POW" or "Point of Delivery"): The point(s) on the NYS Transmission System or Proxy Generator Buses where Energy, Capacity and Ancillary Services will be made available to the receiving party under the ISO OATT or the ISO Services Tariff. (May be referred to as "Point of Delivery" or similar in some Existing Transmission Agreements.)

Pool Control Error ("PCE"): The difference between the actual and scheduled interchange with other Control Areas, adjusted for frequency bias.

Post Contingency: Conditions existing on a system immediately following a Contingency.

Power Exchange ("PE"): A commercial entity meeting the requirements for service under the ISO OATT or the ISO Services Tariff that facilitates the purchase and/or sale of Energy, Unforced Capacity and/or Ancillary Services in a New York Wholesale Market. A PE may transact with the ISO on its own behalf or as an agent for others.

Power Factor: The ratio of real power to apparent power (the product of volts and amperes, expressed in megavolt-amperes, MVA).

Power Factor Criteria: Criteria to be established by the ISO to monitor a Load's use of Reactive Power.

Power Flow: A simulation which determines the Energy flows on the NYS Transmission System and adjacent transmission systems.

Price Adjustment: For each month in the Prior Equivalent Capability Period, the Price Adjustment equals the quotient of dividing (a) the Henry Hub futures gas price for the like month in the succeeding same-season Capability Period by (b) the average Henry Hub spot gas price for that month in the Prior Equivalent Capability Period.

Primary Holder: As defined in the ISO OATT.

Prior Equivalent Capability Period: The previous same-season Capability Period.

Provisional Average Coincident Load ("Provisional ACL"): Prior to the Summer 2014 Capability Period, the value that may be used in lieu of Average Coincident Load for an eligible Special Case Resource for a maximum duration no greater than three consecutive Capability Periods and only where the SCR (i) has not previously been enrolled with the ISO and (ii) never had interval metering Load data available from the Prior Equivalent Capability Period. Beginning with the Summer 2014 Capability Period, the value that may be used in lieu of ACL for an eligible SCR as provided in Section 5.12.11.1.2 of this Services Tariff. A SCR's Provisional ACL is verified subsequent to each eligible Capability Period pursuant to calculations using the SCR's metered Load values in accordance with Sections 5.12.11.1.1 and 5.12.11.1.2 of this Services Tariff and ISO Procedures. Any Load supported by generation produced from a Local Generator, other behind-the-meter generator, or other supply source located behind the SCR's meter operating during the applicable Capability Period SCR Load Zone Peak Hours may not be included in the SCR's metered Load values reported for the verification of its Provisional ACL.

Proxy Generator Bus: A proxy bus located outside the NYCA that is selected by the ISO to represent a typical bus in an adjacent Control Area and at which LBMP prices are calculated. The ISO may establish more than one Proxy Generator Bus at a particular Interface with a neighboring Control Area to enable the NYISO to distinguish the bidding, treatment and pricing of products and services at the Interface.

PSC: The Public Service Commission of the State of New York or any successor agency thereto.

PSL: The New York Public Service Law, Public Service Law § 1 et seq. (McKinney 1989 & Supp. 1997-98).

Public Power Entity: An entity which is either (i) a public authority or corporate municipal instrumentality, including a subsidiary thereof, created by the State of New York that owns or operates generation or transmission and that is authorized to produce, transmit or distribute electricity for the benefit of the public, or (ii) a municipally owned electric system that owns or controls distribution facilities and provides electric service, or (iii) a cooperatively owned electric system that owns or controls distribution facilities and provides electric service.

2.17 Definitions - Q

Qualified Change of Load Condition: A Special Case Resource enrolled with an Average Coincident Load, Provisional Average Coincident Load, or Net Average Coincident Load, in accordance with this Services Tariff, meets a Qualified Change of Load Condition when: (i) the SCR is expected to have a reduction in total Load that meets or exceeds the SCR Load Change Reporting Threshold that is expected to continue for a total period that is greater than seven (7) consecutive days, (ii) the SCR is experiencing a reduction in total Load that meets or exceeds the SCR Load Change Reporting Threshold that is expected to continue for a total period that is greater than seven (7) consecutive days, or (iii) the SCR experienced an unanticipated reduction in total Load that meets or exceeds the SCR Load Change Reporting Threshold for a period greater than seven (7) consecutive days within any month in which the SCR sold capacity or adjoining months in which the SCR sold capacity in either month.

Qualified Change of Status Condition: A Special Case Resource enrolled with an Average Coincident Load, Provisional Average Coincident Load, or Net Average Coincident Load, in accordance with this Services Tariff meets a Qualified Change of Status Condition when: (i) the SCR is expected to have a reduction in total Load that meets or exceeds the SCR Load Change Reporting Threshold that will extend for a period of greater than sixty (60) consecutive days, (ii) the SCR is experiencing a reduction in total Load that meets or exceeds the SCR Load Change Reporting Threshold that is expected to continue for a total period that is greater than sixty (60) consecutive days, or (iii) the SCR has experienced an unanticipated reduction in total Load that meets or exceeds the SCR Load Change Reporting Threshold that has existed for a period greater than sixty (60) consecutive days in which the SCR sold capacity.

Qualified Non-Generator Voltage Support Resource: A resource that is neither a Generator, nor a Distributed Energy Resource, nor a synchronous condenser but that is capable of providing the ISO with Reactive Power on a dynamic basis, that is energized and under the operational control of the ISO, or a Transmission Owner, that meets the resource-specific technical and testing criteria specified in the ISO Procedures, and that is ineligible to receive Reactive Power compensation other than as a Qualified Non-Generator Voltage Support Resource. The Cross-Sound Scheduled Line and the Champlain Hudson Power Express MTF shall be Qualified Non-Generator Voltage Support Resources, provided that they meet the technical and testing criteria in the ISO Procedures.

Quick Start Mode: The setting of a block of generator units capable of remote start-up by a Transmission Owner so that it can synchronize and reach full output within fifteen (15) minutes.

Quick Start Reserves: Capacity of a block of generator units that is set to Quick Start Mode by request of a Transmission Owner.

2.18 Definitions - R

Ramp Capacity: The amount of change in the Desired Net Interchange that generation located in the NYCA can support at any given time. Ramp capacity may be calculated for all Interfaces between the NYCA and neighboring Control Areas as a whole or for any individual Interface between the NYCA and an adjoining Control Area.

RCRR TCC: As defined in the ISO OATT.

Reactive Power (MVAr): The product of voltage and the out-of-phase component of alternating current. Reactive Power, usually measured in MVAr, is produced by capacitors (synchronous condensers), Qualified Non-Generator Voltage Support Resources, and over-excited Generators and absorbed by reactors or under-excited Generators and other inductive devices including the inductive portion of Loads.

Real Power Losses: The loss of Energy, resulting from transporting power over the NYS Transmission System, between the Point of Injection and Point of Withdrawal of that Energy.

Real-Time Bid: A Bid submitted into the Real-Time Commitment before the close of the Real-Time Scheduling Window. A Real-Time Bid shall also include a CTS Interface Bid.

Real-Time Commitment ("RTC"): A multi-period security constrained unit commitment and dispatch model that co-optimizes to solve simultaneously for Load, Operating Reserves and Regulation Service on a least as-bid production cost basis over a two hour and fifteen minute optimization period. The optimization evaluates the next ten points in time separated by fifteen minute intervals. Each RTC run within an hour shall have a designation indicating the time at which its results are posted; "$RTC_{00,}$" "$RTC_{15,}$" "$RTC_{30,}$" and "RTC_{45}" post on the hour, and at fifteen, thirty, and forty-five minutes after the hour, respectively. Each RTC run will produce binding commitment instructions for the periods beginning fifteen and thirty minutes after its scheduled posting time and will produce advisory commitment guidance for the remainder of the optimization period. RTC_{15} will also establish hourly External Transaction schedules, while all RTC runs may establish 15 minute External Transaction schedules at Variably Scheduled Proxy Generator Buses. Additional information about RTC's functions is provided in Section 4.4.2 of this ISO Services Tariff.

Real-Time Dispatch ("RTD"): A multi-period security constrained dispatch model that co-optimizes to solve simultaneously for Load, Operating Reserves, and Regulation Service on a least-as-bid production cost basis over a fifty, fifty-five or sixty-minute period (depending on when each RTD run occurs within an hour). The Real-Time Dispatch dispatches, but does not commit, Resources, except that RTD may commit, for pricing purposes, Resources meeting Minimum Generation Levels and capable of starting in ten minutes. RTD may also establish 5 minute External Transaction schedules at Dynamically Scheduled Proxy Generator Buses. Real-Time Dispatch runs will normally occur every five minutes. Additional information about RTD's functions is provided in Section 4.4.3 of this ISO Services Tariff. Throughout this ISO Services Tariff the term "RTD" will normally be used to refer to both the Real-Time Dispatch and to the specialized Real-Time Dispatch Corrective Action Mode software.

Real-Time Dispatch–Corrective Action Mode ("RTD-CAM"): A specialized version of the Real-Time Dispatch software that will be activated when it is needed to address unanticipated system conditions. RTD-CAM is described in Section 4.4.4 of this ISO Services Tariff.

Real-Time LBMP: The LBMPs established through the ISO Administered Real-Time Market.

Real-Time Market: The ISO Administered Markets for Energy and Ancillary Services resulting from the operation of the RTC and RTD.

Real-Time Minimum Run Qualified Gas Turbine: One or more gas turbines, offered in the Real-Time Market, which, because of their physical operating characteristics, may qualify for a minimum run time of two hours in the Real-Time Market. Characteristics that qualify gas turbines for this treatment are established by ISO Procedures and include using waste heat from the gas turbine-generated electricity to make steam for the generation of additional electricity via a steam turbine.

Real-Time Scheduled Energy: The quantity of Energy that a Supplier is directed to provide in real-time by the ISO. Injections and Demand Reductions are indicated by positive Base Point Signals and withdrawals are indicated by negative Base Point Signals. Unless otherwise directed by the ISO, Dispatchable Supplier's Real-Time Scheduled Energy is equal to its RTD Base Point Signal, or, if it is providing Regulation Service, to its AGC Base Point Signal, and an ISO-Committed Fixed or Self-Committed Fixed Supplier's Real-Time Scheduled Energy is equal to its bid output level in real-time.

Real-Time Scheduling Window: The period of time within which the ISO accepts offers and bids to sell and purchase Energy and Ancillary Services in the Real-Time Market for a given hour which period closes seventy-five (75) minutes before the start of that hour, or eighty-five (85) minutes before the start of that hour for Bids to schedule External Transactions at the Proxy Generator Buses associated with the Cross-Sound Scheduled Line, the Neptune Scheduled Line, the Linden VFT Scheduled Line, the HTP Scheduled Line, or the Champlain Hudson Power Express MTF.

Reconfiguration Auction: As defined in the ISO OATT.

Reference Bus: The location on the NYS Transmission System relative to which all mathematical quantities, including Shift Factors and penalty factors relating to physical operation, will be calculated. The NYPA Marcy 345 kV transmission substation is designated as the Reference Bus.

Reference Month: For purposes of the Net Benefits Test, the calendar month that is twelve months prior to the Study Month.

Regulation Capacity: The Energy capability, measured in MW, that a Regulation Service provider offers and/or which it is scheduled to provide for Regulation Service.

Regulation Capacity Market Price: The price for Regulation Capacity determined by the ISO pursuant to section 15.3 of this Services Tariff.

Regulation Capacity Response Rate: The Regulation Capacity a Resource is capable of providing over five minutes, measured in MW/minute which shall not exceed the lowest normal energy response rate provided for the Resource and which must be sufficient to permit that Resource to provide the Regulation Capacity (in MW) offered within a five-minute RTD interval. Reference to a Regulation response rate shall be a reference to the Regulation Capacity Response Rate.

Regulation Movement: The absolute value of the change in Energy over a six second interval, measured in MW, that a Regulation Service provider is instructed to deliver for the purpose of providing Regulation Service.

Regulation Movement Market Price: The price for Regulation Movement as determined by the ISO pursuant to section 15.3 of this Services Tariff.

Regulation Movement Multiplier: A factor, used with the Regulation Movement Bids, to schedule Regulation Service providers in both the Day-Ahead and Real-Time Markets. The ISO calculates the Regulation Movement Multiplier, pursuant to ISO Procedures, based on the historical relationship between the number of MW of Regulation Capacity that the ISO seeks to maintain in each hour and the number of Regulation Movement MW instructed by AGC in each hour.

Regulation Movement Response Rate: The amount of Regulation Movement a Regulation Service provider is capable of delivering in six seconds which shall not be less than, but can be equal to or greater than, the Regulation Capacity Response Rate equivalent.

Regulation Service: The Ancillary Service defined by the Commission as "frequency regulation" and that is instructed as Regulation Capacity in the Day-Ahead Market and as Regulation Capacity and Regulation Movement in the Real-Time Market as is further described in Section 15.3 of the Services Tariff. Day-Ahead and Real-Time Bids to provide Regulation Service shall include a Bid for Regulation Capacity and a Bid for Regulation Movement. The Regulation Service requirement or target level shall be for MW of Regulation Capacity.

Regulation Service Demand Curve: A series of quantity/price points that defines the maximum Shadow Price for Regulation Service corresponding to each possible quantity of Resources that the ISO's software may schedule to satisfy the ISO's Regulation Service constraint. A single Regulation Service Demand Curve will apply to both the Day-Ahead Market and the Real-Time Market for Regulation Service. The Shadow Price for Regulation Service shall be used to calculate Regulation Service payments under Rate Schedule 3 of this ISO Services Tariff.

Regulation Revenue Adjustment Charge ("RRAC"): A charge that will be assessed against certain Regulation Service Providers that are providing Regulation Service under Section 15.3.6 of Rate Schedule 3 to this ISO Services Tariff.

Regulation Revenue Adjustment Payment ("RRAP"): A payment that will be made to certain Regulation Service Providers that are providing Regulation Service under Section 15.3.6 of Rate Schedule 3 to this ISO Services Tariff.

Reliability Rules: Those rules, standards, procedures and protocols developed and promulgated by the NYSRC, including Local Reliability Rules, in accordance with NERC, NPCC, FERC, PSC and NRC standards, rules and regulations and other criteria and pursuant to the NYSRC Agreement.

Repair Plan: A work plan, set of actions, and time frame for such actions, that is necessary to repair a Generator and return it to service as described in Section 5.18.1 of this Services Tariff**.**

Required System Capability: Generation capability required to meet an LSE's peak Load plus Installed Capacity Reserve obligation as defined in the Reliability Rules.

Residual Adjustment: The adjustment made to ISO costs that are recovered through Schedule 1 of the OATT. The Residual Adjustment is calculated pursuant to Schedule 1 of the OATT.

Residual Capacity Reservation Right ("RCRR"): As defined in the ISO OATT.

Residual Transmission Capacity: As defined in the ISO OATT.

Resource: An Aggregation, or an Energy Limited Resource, Energy Storage Resource, Limited Energy Storage Resource, Generator, Installed Capacity Marketer, Special Case Resource, Intermittent Power Resource, Limited Control Run of River Hydro Resource, municipally-owned generation, System Resource, BTM:NG Resource, Demand Side Resource or Control Area System Resource that is not participating in an Aggregation.

Resource with Energy Duration Limitation: A Resource that is not capable of supplying its ICAP equivalent of UCAP sold in each hour of the day due to a run-time limitation, such as an Energy storage limitation or permit restriction, and has elected an Energy Duration Limitation as specified in Section 5.12.14 of the ISO Services Tariff.

Responsible Interface Party ("RIP"): A Customer that is authorized by the ISO to be the Installed Capacity Supplier for one or more Special Case Resources and that agrees to certain notification and other requirements as set forth in this Services Tariff and in the ISO Procedures.

Rest of State: The set of all non-Locality NYCA LBMP Load Zones. As of the 2014/2015 Capability Year, Rest of State includes all NYCA LBMP Load Zones other than LBMP Load Zones G, H, I, J and K.

Retired: A Generator that has permanently ceased operating on or after May 1, 2015 either: i) pursuant to applicable notice; or ii) as a result of the expiration of its Mothball Outage or of its ICAP Ineligible Forced Outage.

RMR Agreement: Shall have the meaning specified in Section 1.18 of the ISO's Open Access Transmission Tariff.

RMR Avoidable Costs: Shall have the meaning specified in Section 1.18 of the ISO's Open Access Transmission Tariff.

RMR Generator: Shall have the meaning specified in Section 1.18 of the ISO's Open Access Transmission Tariff.

Rolling RTC: The RTC run that is used to schedule a given 15-minute External Transaction. The Rolling RTC may be an RTC00, RTC15, RTC30 or RTC45 run.

Roundtrip Efficiency: The ratio of energy injections to energy withdrawals for an Energy Storage Resource or Aggregation comprised entirely of Energy Storage Resources.

2.19 Definitions - S

Safe Operations: Actions which avoid placing personnel and equipment in peril with regard to the safety of life and equipment damage.

Scarcity Reserve Demand Curve: A series of quantity/price points that defines the maximum Shadow Price for Operating Reserves to meet a Scarcity Reserve Requirement for which the pricing rules established in Section 15.4.6.1.1(b) of Rate Schedule 4 of this ISO Services Tariff apply corresponding to each possible quantity of Resources that the ISO's software may schedule to satisfy that requirement. A single Scarcity Reserve Demand Curve will apply to the Real-Time Market for each such Scarcity Reserve Requirement.

Scarcity Reserve Region: A Load Zone or group of Load Zones containing EDRP and/or SCRs that have been called by the ISO to address the same reliability need, as such reliability need is determined by the ISO.

Scarcity Reserve Requirement: A 30-Minute Reserve requirement established by the ISO for a Scarcity Reserve Region in accordance with Rate Schedule 4 of this ISO Services Tariff.

Scheduled Energy Injections: As defined in the ISO OATT.

Scheduled Energy Withdrawals: As defined in the ISO OATT.

Scheduled Line: A transmission facility or set of transmission facilities: (a) that provide a distinct scheduling path interconnecting the ISO with an adjacent control area, (b) over which Customers are permitted to schedule External Transactions, (c) for which the ISO separately posts TTC and ATC, and (d) for which there is the capability to maintain the Scheduled Line actual interchange at the DNI, or within the tolerances dictated by Good Utility Practice. Each Scheduled Line is associated with a distinct Proxy Generator Bus. Transmission facilities shall only become Scheduled Lines after the Commission accepts for filing revisions to the NYISO's tariffs that identify a specific set or group of transmission facilities as a Scheduled Line. The transmission facilities that are Scheduled Lines are identified in Section 4.4.4 of the Services Tariff.

SCR Aggregation: One or more Special Case Resources registered by the Responsible Interface Party at a single PTID, with the Load of each Special Case Resource electrically located within the same single Load Zone and the total of all Loads at the PTID greater than or equal to 0.1 MW.

SCR Change of Load: A decrease in the Load of the SCR that meets the criteria of a Qualified Change of Load Condition and the SCR Load Change Reporting Threshold in accordance with this Services Tariff and results in a total Load reduction, within the range of hours that corresponds with the Capability Period SCR Load Zone Peak Hours, and the total Load reduction persists for more than seven (7) and less than or equal to sixty (60) continuous days from the first date of the reduction of the Load.

SCR Change of Status: The decrease to be treated as an adjustment to the applicable Average Coincident Load of a Special Case Resource when the SCR meets the criteria of a Qualified

Change of Status Condition and the SCR Load Change Reporting Threshold in accordance with this Services Tariff and results in a total Load reduction, within the range of hours that corresponds with the Capability Period SCR Load Zone Peak Hours, and the total Load reduction persists for more than sixty (60) continuous days from the first date of the reduction of the Load.

SCR Load Change Reporting Threshold: For a Special Case Resource with an applicable ACL greater than or equal to 500 kW, a reduction or increase in total Load not attributable to fluctuations in Load due to weather as described in ISO Procedures, that is equal to or greater than (i) thirty (30) percent of the applicable ACL for any month within the Capability Period, or (ii) five (5) MW in the NYC Locality or ten(10) MW if in any other Load Zone; whichever is less. For SCRs that elect to enroll with an Incremental ACL and do not increase the eligible Installed Capacity associated with the SCR, the RIP may enroll the SCR with a lower percentage change to its total Load increase as specified in Section 5.12.11.1.5 of this Services Tariff.

SCUC: Security Constrained Unit Commitment, described in Section 4.2.4 of this ISO Services Tariff.

Secondary Holder: As defined in the ISO OATT.

Second Settlement: The process of: (1) identifying differences between Energy production, Energy consumption or NYS Transmission System usage scheduled in a First Settlement and actual production, consumption, or usage during the Dispatch Day; and (2) assigning financial responsibility for those differences to the appropriate Customers and Market Participants. Charges for Energy supplied (to replace generation deficiencies or unscheduled consumption), and payments for Energy consumed (to absorb consumption deficiencies or excess Energy supply) or changes in transmission usage will be based on the Real-Time LBMPs.

Secondary Market: As defined in the ISO OATT.

Security Coordinator: An entity that provides the security assessment and Emergency operations coordination for a group of Control Areas. A Security Coordinator must not participate in the wholesale or retail merchant functions.

Self-Committed Fixed: A bidding mode in which a Generator or Aggregation is self-committed and opts not to be Dispatchable over any portion of its operating range.

Self-Committed Flexible: A bidding mode in which a Dispatchable Generator or Aggregation follows Base Point Signals within a portion of its operating range, but self-commits.

Self-Managed Energy Level: A Bid parameter which when selected indicates that an Energy Storage Resource's, or Aggregation comprised entirely of Energy Storage Resources, Energy Level constraints will not be directly accounted for in the optimization. *See* Sections 4.2.1.3.4 and 4.4.2.1 of this Services Tariff.

Self-Supply: The provision of certain Ancillary Services, or the provision of Energy to replace Marginal Losses by a Transmission Customer using either the Transmission Customer's own Generators or generation obtained from an entity other than the ISO.

Service Agreement: The agreement, in the form of Attachment A to the Tariff, and any amendments or supplements thereto entered into by a Customer and the ISO of service under the Tariff, or any unexecuted Service Agreement, amendments or supplements thereto, that the ISO unilaterally files with the Commission.

Service Commencement Date: The date that the ISO begins to provide service pursuant to the terms of a Service Agreement, or in accordance with the Tariff.

Settlement: The process of determining the charges to be paid to, or by, a Customer to satisfy its obligations.

Shadow Price: The marginal value of relieving a particular Constraint which is determined by the reduction in system cost that results from an incremental relaxation of that Constraint.

Shift Factor ("SF"): A ratio, calculated by the ISO, that compares the change in power flow through a transmission facility resulting from the incremental injection and withdrawal of power on the NYS Transmission System.

Shutdown Period: An ISO approved period of time immediately following a shutdown order, such as a zero base point, that has been designated by the Customer, during which unstable operation prevents the unit from accurately following its base points. The Shut-Down Period shall be set to zero for a BTM:NG Resource, an Energy Storage Resource, and an Aggregation.

Sink Price Cap Bid: A monotonically increasing Bid curve provided by an entity engaged in an Export, other than an entity submitting a CTS Interface Bid, to indicate the relevant Proxy Generator Bus LBMP at or below which that entity is willing to either purchase Energy in the LBMP Markets or, in the case of Bilateral Transactions, to accept Transmission Service, where the MW amounts on the Bid curve represent the desired increments of Energy that the entity is willing to purchase at various price points.

Southeastern New York ("SENY"): An electrical area comprised of Load Zones G, H, I, J, and K, as identified in the ISO Procedures.

Special Case Resource ("SCR"): Demand Side Resources whose Load is capable of being interrupted upon demand at the direction of the ISO, and/or Demand Side Resources that have a Local Generator, which is not visible to the ISO's Market Information System and is rated 100 kW or higher, that can be operated to reduce Load from the NYS Transmission System or the distribution system at the direction of the ISO. Special Case Resources are subject to special rules, set forth in Section 5.12.11.1 of this ISO Services Tariff and related ISO Procedures, in order to facilitate their participation in the Installed Capacity market as Installed Capacity Suppliers.

Special Case Resource Capacity: The Installed Capacity Equivalent of the Unforced Capacity which has been sold by a Special Case Resource in the Installed Capacity market during the current Capability Period.

Start-Up Bid: A Bid parameter that may vary hourly and that identifies the payment a Supplier requires to bring a Generator up to its specified minimum operating level from an offline state.

If the Supplier is a BTM:NG Resource, Energy Storage Resource, or an Aggregation, it shall not submit a Start-Up Bid.

Start-Up Bids submitted for a Generator that is not able to complete its specified minimum run time (of up to a maximum of 24 hours) within the Dispatch Day are expected to include expected net costs related to the hour(s) that a Generator needs to run on the day following the Dispatch Day in order to complete its minimum run time. The component of the Start-Up Bid that incorporates costs that the Generator expects to incur on the day following the Dispatch Day is expected to reflect the operating costs that the Supplier does not expect to be able to recover through LBMP revenues while operating to meet the Generator's minimum run time, at the minimum operating level Bid for that Generator for the hour of the Dispatch Day in which the Generator is scheduled to start-up. Settlement rules addressing Start-Up Bids that incorporates costs related to the hours that a Generator needs to run on the day following the Dispatch Day on which the Generator is committed are set forth in Attachment C to this ISO Services Tariff.

Start-Up Period: An ISO approved period of time immediately following synchronization to the Bulk power system, which has been designated by a Customer and bid into the Real-Time Market, during which unstable operation prevents the unit from accurately following its base points. The Start-Up Period shall be set to zero for a BTM:NG Resource and Energy Storage Resource and an Aggregation.

Station Power: Station Power shall mean the Energy used by a Generator:

1. for operating electric equipment located on the Generator site, or portions thereof, owned by the same entity that owns the Generator, which electrical equipment is used by the Generator exclusively for the production of Energy and any useful thermal energy associated with the production of Energy; and
2. for the incidental heating, lighting, air conditioning and office equipment needs of buildings, or portions thereof, that are: owned by the same entity that owns the Generator; located on the Generator site; and
3. used by the Generator exclusively in connection with the production of Energy and any useful thermal energy associated with the production of Energy.

Station Power does not include any Energy: (i) used to power synchronous condensers; (ii) used for pumping at a pumped storage facility or for charging Limited Energy Storage Resources and Energy Storage Resources when that Energy is stored for later injection back to the grid; (iii) provided during a Black Start restoration by Generators that provide Black Start Capability Service; (iv) used by a Resource in an Aggregation; or (v) used by an enhanced Fast-Start Resource to charge its battery.

Storm Watch: Actual or anticipated severe weather conditions under which region-specific portions of the NYS Transmission System are operated in a more conservative manner by reducing transmission transfer limits.

Strandable Costs: Prudent and verifiable expenditures and commitments made pursuant to a Transmission Owner's legal obligations that are currently recovered in the Transmission Owner's retail or wholesale rate that could become unrecoverable as a result of a restructuring of

the electric utility industry and/or electricity market, or as a result of retail-turned-wholesale customers, or customers switching generation or Transmission Service suppliers.

Stranded Investment Recovery Charge: A charge established by a Transmission Owner to recover Strandable Costs.

Study Month: The calendar month for which the ISO calculates the Monthly Net Benefit Offer Floor, in accordance with Section 4.2.1.9 of the ISO Services Tariff and ISO Procedures.

Subject Transaction: As defined in the ISO OATT.

Subject Transaction Financially Responsible Party: As defined in the ISO OATT.

Subzone: That portion of a Load Zone in a Transmission Owner's Transmission District.

Supplemental Event Interval: Any RTD interval in which there is a maximum generation pickup or a large event reserve pickup or which is one of the three RTD intervals following the termination of the maximum generation pickup or the large event reserve pickup.

Supplemental Resource Evaluation ("SRE"): A determination of (i) the least cost selection of additional Generators or Aggregations, which are to be committed 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 meet the reliability requirements of the Transmission Owner's local system or to meet Load or reliability requirements of the ISO; or (ii) the least cost selection of additional Generators, which are committed to meet forecast Load and reserve requirements over the six-day period that follows the Dispatch Day. An Aggregation or ESR is expected to be available in real-time and capable of injecting Energy at its full capability for all of the SRE commitment hours it receives.

Supplier: A Party that is supplying the Capacity, Energy and/or associated Ancillary Services to be made available under the ISO OATT or the ISO Services Tariff, including Generators, BTM:NG Resources, Energy Storage Resources, Demand Side Resources, and Aggregations that satisfy all applicable ISO requirements.

System Resource: A portfolio of Unforced Capacity provided by Resources located in a single ISO-defined Locality, the remainder of the NYCA, or any single External Control Area, that is owned by or under the control of a single entity, which is not the operator of the Control Area where such Resources are located, and that is made available, in whole or in part, to the ISO.

2.20 Definitions - T

Tangible Net Worth: The value, determined by the ISO, of all of a Customer's assets less both: (i) the amount of the Customer's liabilities and (ii) all of the Customer's intangible assets, including, but not limited to, patents, trademarks, franchises, intellectual property, and goodwill.

Testing Period: An ISO approved period of time during which a Generator is testing equipment and during which unstable operation prevents the unit from accurately following its base points.

Third Party Transmission Wheeling Agreements ("Third Party TWAs"): A Transmission Wheeling Agreement, as amended, between Transmission Owners or between a Transmission Owner and an entity that is not a Transmission Owner. Third Party TWAs are associated with the purchase (or sale) of Energy, Capacity, and/or Ancillary Services for the benefit of an entity that is not a Transmission Owner. All Third Party TWAs are listed in Table 1 A of Attachment L to the ISO OATT, and are designated in the "Treatment "column of Table 1A, as "Third Party TWA."

Total Transfer Capability ("TTC"): The amount of electric power that can be transferred over the interconnected transmission network in a reliable manner**.**

Trading Hub: A virtual location in a given Load Zone, modeled as a Generator bus and/or Load bus, for scheduling Bilateral Transactions in which both the POI and POW are located within the NYCA.

Trading Hub Energy Owner: A Customer who buys energy in a Bilateral Transaction in which the POW is a Trading Hub, or who sells energy in a Bilateral Transaction in which the POI is a Trading Hub.

Transaction: The purchase and/or sale of Energy or Capacity, or the sale of Ancillary Services. A Transaction bid into the Energy market to sell or purchase Energy or to schedule a Bilateral Transaction includes a Point of Injection and a Point of Withdrawal.

Transfer Capability: The measure of the ability of interconnected electrical systems to reliably move or transfer power from one area to another over all transmission facilities (or paths) between those areas under specified system conditions.

Transmission Congestion Contract Component ("TCC Component"): A component of the Operating Requirement, calculated in accordance with Section 26.4.2 of Attachment K to this Services Tariff.

Transmission Congestion Contracts ("TCCs"): As defined in the ISO OATT.

Transmission Customer: Any entity (or its designated agent) that requests or receives Transmission Service pursuant to a Service Agreement and the terms of the ISO OATT.

Transmission District: The geographic area in which a Transmission Owner, including LIPA, is obligated to serve Load, as well as the customers directly interconnected with the transmission facilities of the Power Authority of the State of New York.

Transmission Facilities Under ISO Operational Control: The transmission facilities of the Transmission Owners listed in Appendix A-1 of the ISO/TO Agreement ("Listing of Transmission Facilities Under ISO Operational Control") and listed in Appendix A-1 of an Operating Agreement ("NTO Transmission Facilities Under ISO Operational Control") that are subject to the Operational Control of the ISO. This listing may be amended from time-to-time as specified in the ISO/TO Agreement and Operating Agreements.

Transmission Facilities Requiring ISO Notification: The transmission facilities of the Transmission Owners listed in Appendix A-2 of the ISO/TO Agreement ("Listing of Transmission Facilities Requiring ISO Notification") and listed in Appendix A-2 of an Operating Agreement ("NTO Transmission Facilities Requiring ISO Notification") whose status of operation must be provided to the ISO by the Transmission Owners (for the purposes stated in the ISO Tariffs and in accordance with the ISO Tariffs, ISO/TO Agreement, and/or Operating Agreements) prior to the Transmission Owners making operational changes to the state of these facilities. This listing may be amended from time-to-time as specified in the ISO/TO Agreement and Operating Agreements.

Transmission Facility Agreement ("TFA"): Agreements governing the use of specific or designated transmission facilities charges to cover all, or a portion, of the costs to install, own, operate, or maintain transmission facilities, to the customer under the agreement and that have provisions to provide Transmission Service utilizing said transmission facilities. All Transmission Facility Agreements are listed in Attachment L. Table 1A, and are designated in the "Treatment" column as "Facility Agmt. – MWA."

Transmission Fund ("T-Fund"): The mechanism used under the current NYPP Agreement to compensate the Member Systems for providing Transmission Service for economy Energy Transactions over their transmission systems. Each Member System is allocated a share of the economy Energy savings in dollars assigned to the fund that is based on the ratio of their investment in transmission facilities to the sum of investments in transmission and generation facilities.

Transmission Node: A bus located inside the NYCA that is identified by the ISO to represent an electrical area to which individual Distributed Energy Resources may aggregate and at which LBMPs are calculated.

Transmission Owner: The public utility or authority (or its designated agent) that owns facilities used for the transmission of Energy in interstate commerce and provides Transmission Service under the Tariff.

Transmission Owner's Monthly Transmission System Peak: The maximum hourly firm usage as measured in megawatts ("MW") of the Transmission Owner's transmission system in a calendar month.

Transmission Reliability Margin ("TRM"): The amount of TTC reserved by the ISO to ensure the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions.

Transmission Service: Point-To-Point Network Integration or Retail Access Transmission Service provided under the ISO OATT.

Transmission Service Charge ("TSC"): A charge designed to ensure recovery of the embedded cost of a transmission system owned by a Member System.

Transmission Shortage Cost: A pricing mechanism utilized in determining the Shadow Price of a particular transmission Constraint that will be used in calculating LBMP in accordance with Section 17.1.4 of Attachment B of this ISO Services Tariff.

Transmission System: The facilities operated by the ISO that are used to provide Transmission Services under the ISO OATT.

Transmission Usage Charge ("TUC"): Payments made by the Transmission Customer to cover the cost of Marginal Losses and, during periods of time when the transmission system is constrained, the marginal cost of Congestion. The TUC is equal to the product of: (1) the LBMP at the POW minus the LBMP at the POI (in $/MWh); and (2) the scheduled or delivered Energy (in MWh).

Transmission Wheeling Agreement ("TWA"): The Agreements listed in Table 1A of Attachment L to the ISO OATT governing the use of specific or designated transmission facilities that are owned, controlled or operated by an entity for the transmission of Energy in interstate commerce. TWAs between Transmission Owners have been modified such that all TWAs between Transmission Owners are now MWAs.

Triggering Resource: A potential new Installed Capacity Supplier (including an Installed Capacity Supplier holding rights to new UDRs): (1) whose commencement of participation in the ICAP market during a Capability Year would change the contingencies evaluated in assessing the transfer capability into a Locality for purposes of establishing the transmission security limit for such Locality pursuant to Section 5.11.4 of this ISO Services Tariff for such Capability Year; and (2) as of the date the NYSRC approves the NYCA Installed Reserve Margin applicable to such Capability Year, such potential new Installed Capacity Supplier (a) has obtained Capacity Resource Interconnection Service pursuant to the applicable provisions of Attachment S or Attachment HH to the ISO OATT, (b) is a Cluster Study CRIS Project and the Phase 2 Study of the Cluster Study Process or Transition Cluster Study Process (as such terms are defined in Section 40.1 of Attachment HH to the ISO OATT) that includes such potential new Installed Capacity Supplier has commenced, or (c) is a project that is a member of an Expedited Deliverability Study and such Expedited Deliverability Study has commenced.

2.21 Definitions - U

Uncertainty Reserve Requirements: A component of the Operating Reserves requirements in the Day-Ahead and Real-Time Markets to address the uncertainties of Load forecasts and the Wind and Solar Energy Forecasts. The Uncertainty Reserve Requirements will be calculated each day before the Day-Ahead Market close and will apply to the 24-hours of the Day-Ahead Market day and the corresponding Real-Time Market day. Uncertainty Reserve Requirements will be calculated pursuant to ISO Procedures using historical forecast error metrics and Day-Ahead Market forecast information.

Unforced Capacity: The measure by which Installed Capacity Suppliers will be rated, in accordance with formulae set forth in the ISO Procedures, to quantify the extent of their contribution to satisfy the NYCA Installed Capacity Requirement, and which will be used to measure the portion of that NYCA Installed Capacity Requirement for which each LSE is responsible.

Unforced Capacity Deliverability Rights: Unforced Capacity Deliverability Rights ("UDRs") are rights, as measured in MWs, associated with (i) new incremental controllable transmission projects, and (ii) new projects to increase the capability of existing controllable transmission projects that have UDRs, that provide a transmission interface to a Locality. When combined with Unforced Capacity which is located in an External Control Area or non-constrained NYCA region either by contract or ownership, and which is deliverable to the NYCA interface in the Locality in which the UDR transmission facility is electrically located, UDRs allow such Unforced Capacity to be treated as if it were located in the Locality, thereby contributing to an LSE's Locational Minimum Installed Capacity Requirement. To the extent the NYCA interface is with an External Control Area the Unforced Capacity associated with UDRs must be deliverable to the Interconnection Point.

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

Unrated Customer: A Customer that does not currently have a senior long-term unsecured debt rating or issuer rating from Standard & Poor's, Moody's, Fitch, or Dominion, and that has not received an ISO Equivalency Rating.

Unsecured Credit: A basis for satisfying part of a Customer's Operating Requirement on the basis of the Customer's creditworthiness. The amount of a Customer's Unsecured Credit shall be determined in accordance with Section 26.5 of Attachment K to this Services Tariff.

Upper Storage Limit: The maximum amount of Energy an Energy Storage Resource, or an Aggregation comprised entirely of Energy Storage Resources, is physically capable of storing.

2.22 Definitions - V

Variably Scheduled Proxy Generator Bus: A Proxy Generator Bus for which the ISO may schedule Transactions at 15 minute intervals in real time. Variably Scheduled Proxy Generator Buses are identified in Section 4.4.4 of the Services Tariff.

Verified Average Coincident Load ("Verified ACL"): The Average Coincident Load determined by the ISO with verification data provided by the RIP for SCRs enrolled with a Provisional Average Coincident Load, as calculated pursuant to Section 5.12.11.1.2 of this Services Tariff, or, beginning with the Summer 2014 Capability Period, for resources with a reported Incremental Average Coincident Load, as calculated pursuant to Section 5.12.11.1.5 of this Services Tariff. The Verified ACL shall be used to evaluate the SCR's event responses for performance and in the calculation of the SCR's performance factor and all associated performance factors, deficiencies and penalties.

Virtual Load: Any Bid to purchase Energy in the Day-Ahead Market submitted at a load bus specified for Virtual Transactions.

Virtual Supply: Any Bid to sell Energy in the Day-Ahead Market submitted at a load bus specified for Virtual Transactions.

Virtual Transaction: Any Bid to purchase or sell Energy in the Day-Ahead Market submitted at a load bus specified for Virtual Transactions.

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

2.23 Definitions - W

West of Central-East ("West" or "Western"): An electrical area comprised of Load Zones A, B, C, D, and E, as identified in the ISO Procedures.

Wheels Through: Transmission Service, originating in another Control Area, that is wheeled through the NYCA to another Control Area.

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

Wholesale Market: The sum of purchases and sales of Energy and Capacity for resale along with Ancillary Services needed to maintain reliability and power quality at the transmission level coordinated together through the ISO and Power Exchanges. A party who purchases Energy, Capacity or Ancillary Services in the Wholesale Market to serve its own Load is considered to be a participant in the Wholesale Market.

Wholesale Transmission Services Charges ("WTSC"): Those charges calculated pursuant to Attachment H of the OATT, incurred or declared overdue by a Transmission Owner pursuant to Section 26.4.2 of Attachment K, after the effective date of these revisions; provided, however, that these provisions will not apply to pre-petition bankruptcy debts for a company that is currently in bankruptcy.

Wind and Solar Energy Forecast: The ISO's forecast of Energy that is expected to be supplied over a specified interval of time by an Intermittent Power Resource that depends on wind or solar energy as its fuel and which is used in ISO's Energy market commitment and dispatch. The Wind Energy Forecast does not include a forecast of Energy for Intermittent Power Resources depending on wind as its fuel that participate in a DER Aggregation.

Wind and Solar Output Limit: A Base Point Signal calculated for an Intermittent Power Resource depending on wind or solar energy as its fuel and which, when sent to the Intermittent Power Resource, shall include a separate flag directing the Intermittent Power Resource not to exceed its Base Point Signal. Intermittent Power Resources that depend on wind or solar energy as their fuel shall be eligible to receive a Wind and Solar Output Limit, except for those that depend on wind for their fuel and were in commercial operation as of January 1, 2002 with name plate capacity of 12 MWs or fewer, and Resources depending on wind or solar energy as their fuel that participate in a DER Aggregation.

Intermittent Power Resources depending on wind or solar energy or landfill gas as their fuel, or a Limited Control Run of River Hydro Resource, that participate as Co-located Storage Resources shall be eligible to receive a Wind and Solar Output Limit to address the real-time variability of their Energy deliveries consistent with the rules specified for implementing CSR Scheduling Limits.

Withdrawal-Eligible Generator: A Generator that is eligible to withdraw energy from the grid at a price for the purposes of recharging or refilling for later injection back into the grid.

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

2.24 Definitions - X

2.25 Definitions - Y

2.26 Definitions - Z

3 Term and Effectiveness

3.1 Effectiveness

The ISO Services Tariff shall become effective on the latest of: (i) Commission approval of: (a) the ISO OATT, (b) the ISO Services Tariff, (c) the ISO Agreement, (d) the NYSRC Agreement, (e) the ISO/NYSRC Agreement, and (f) the ISO/TO Agreement; (ii) the date on which both the Commission and the PSC grant all necessary approvals to the Member Systems to transfer Operational Control of any facilities to the ISO or otherwise dispose of any of their property, including, without limitation, those approvals required under Section 70 of the New York Public Service Law ("PSL") and Section 203 of the Federal Power Act ("FPA"); (iii) the last date that any other approval or authorization is received, to the extent such additional approval or authorization is necessary; (iv) execution of the ISO Related Agreements with the exception of any Operating Agreement; or (v) such later date specified by the Commission.

3.2 Term and Termination

The ISO Services Tariff shall remain in effect until: (i) canceled by the ISO upon sixty (60) days prior written notice in accordance with applicable Commission regulations; or (ii) the effective date of any law, order, rule, regulation, or determination of a body of competent jurisdiction requiring termination or a material modification of the ISO Services Tariff and/or the Service Agreements executed pursuant to the terms of the Tariff (See Attachment A) that would be inconsistent with any material term or provision of the ISO/TO Agreement. Any Customer may withdraw from the Tariff on thirty (30) days prior notice to the ISO; provided, however, that an LSE is required to be a Customer and comply with applicable requirements of the Tariff as long as it continues to serve Load in the NYCA.

3.3 Regulations

The ISO Services Tariff and any related Service Agreement are made subject to all applicable federal, state and local laws, regulations and orders.

3.4 Access to Complete and Accurate Data

Customers under the Tariff shall provide to the ISO such information and data as the ISO reasonably deems necessary in order to perform its functions and fulfill its responsibilities under the Tariff and in accordance with the ISO Market Power Monitoring Program. Such information will be provided on a timely basis and in the formats prescribed in the ISO Procedures. The ISO shall establish metering specifications and standards for all metering that is used as a data source by the ISO (See Article 13). Customers shall install and maintain such metering at their own expense and deliver data to the ISO without charge.

3.5 ISO Procedures

The ISO shall develop, and modify as appropriate, procedures for the efficient and non-discriminatory operation of the ISO Administered Markets and for the safe and reliable operation of the NYCA in accordance with the terms and conditions of the Tariff. All such procedures must be consistent with Good Utility Practice.

3.5.1 Market Problems Reporting Procedure

Upon ISO discovery of a potential Market Problem, the ISO will immediately report the Market Problem to the Market Monitoring Unit and to the Commission's Office of Enforcement.

The ISO will then report the Market Problem to Market Participants, subject to applicable confidentiality restrictions, unless it is determined in consultation with Commission staff that disclosure could lead to gaming or other harmful outcomes. The report will also be provided to Market Participants in an e-mail notice with this subject line: "Notice of a Market Problem."

The ISO will accomplish all three of the above steps as soon as possible, but in no event longer than five calendar days after discovery of the potential Market Problem.

In the event of a determination that disclosure of a Market Problem could lead to gaming or other harmful outcomes, ISO, unless otherwise directed by Commission staff, will provide notice to the Market Participants of the identification of a potential Market Problem and the conduct of a confidential investigation. Thereafter, the ISO shall consult with Market Participants as soon as practicable after resolution of the underlying issue pursuant to direction from the Commission.

In the event of an exigent circumstances filing of tariff amendments pursuant to Article 19 of the ISO Agreement, this consultation would include seeking concurrence on the Section 205 filing from the Management Committee.

If no exigent circumstances filing is made, the ISO will provide an opportunity for Market Participants to comment prior to a request to FERC for a tariff waiver or other remedy. In the ISO's reports to Market Participants, subject to applicable confidentiality restrictions, the NYISO will provide the following information:

- Description of the Market Problem and tariff implications as appropriate;
- Description of the time frame involved;
- Description of underlying cause of the Market Problem;
- Description of economic impacts; and
- Description of steps planned or taken to address the Market Problem including a proposed timetable for the developing necessary tariff revisions, if applicable, as developed in consultation with Market Participants. The ISO will also report when it determines a Market Problem investigation has concluded.

Except where a longer period of analysis is required, the ISO will provide an explanation to all Market Participants of its proposed steps to address the Market Problem as soon as reasonably possible, but in no event later than 30 calendar days of its initial notice to Market Participants and the ISO shall make staff available to discuss proposed remedy at the appropriate working group or committee with advance notice to all Market Participants. Where a longer period of analysis is required, the ISO will provide updates to Market Participants at least quarterly.

3.5.2 Provision of Data By Market Participants

Whenever requested by the ISO, each LSE shall provide the ISO with a forecast of the Loads for which it is responsible for the particular time period designated by the ISO. Customers shall inform the ISO, in accordance with the ISO Procedures, of the Availability of Generators within the NYCA subject to a Customer's control by Energy contract, ownership or otherwise. Additionally, the Transmission Owners will provide megawatt, megavar, voltage

readings, transmission system data (facility ratings and impedance data), and maintenance schedules for all Transmission Facilities Under ISO Operational Control, and any person or entity that owns transmission facilities associated with an award of Incremental TCCs under Section 19.2.2 of Attachment M to the ISO OATT shall be responsible for providing the same data and schedules to the ISO. For Transmission Facilities Requiring ISO Notification, the Transmission Owners shall inform the ISO of all changes in the status of the designated transmission facilities. Transmission Owners and persons or entities that own transmission facilities associated with an award of Incremental TCCs shall provide such data and schedules pursuant to applicable provisions of the ISO Procedures. Suppliers will provide data on Generator status and output including maintenance schedules, Generator scheduled return dates (inclusive of return to service from maintenance, forced outages, partial unit outages or an increase in the forecasted Host Load of a Behind-the-Meter Net Generation Resource in real-time compared to the forecasted Host Load submitted as part of its Energy Bid in the Day-Ahead Market that resulted in a significant reduction in a generating unit's or a Behind-the-Meter Net Generation Resource's ability to produce Energy in any hour), and Generator machine data, in accordance with the ISO Procedures. These data shall also include Generator Incremental/Decremental Bids, operating limits, response rates, megawatt, megavar, and voltage readings. Energy Storage Resources are required to provide a real-time Energy Level signal to the NYISO in accordance with ISO Procedures.

3.5.3 Provision of Data By Transmission Owners to Each Other

Each Transmission Owner shall make available information regarding its Transmission Facilities Under ISO Operational Control, Transmission Facilities Requiring ISO Notification, and Local Area Transmission Facilities to the other Transmission Owners in the New York

Control Area as follows: (i) a Transmission Owner must make available the maintenance schedules for its transmission facilities described above to any other Transmission Owner in the New York Control Area whose facilities would be directly impacted by the maintenance schedules; and (ii) a Transmission Owner must make available to all other Transmission Owners in the New York Control Area the results of its investigations of equipment malfunctions and failures and forced transmission outages of its transmission facilities described above. Except for such information posted by the ISO pursuant to its outage scheduling procedures, each Transmission Owner shall treat such information as Confidential Information and restrict access to only those persons authorized to view such information by FERC's Standards of Conduct in 18 C.F.R § 358, and, if more restrictive, by each Transmission Owner's board resolutions, tariff provisions, or other internal policies governing access to, and the sharing of Transmission System Information as that term is defined in Attachment F of the ISO OATT.

3.6 Survival

Upon termination, expiration or cancellation of the ISO Services Tariff or any related Service Agreement, in accordance with their terms, the provisions of the Tariff, and any Service Agreement, shall remain in effect to the extent necessary to permit the conclusion of: (i) transactions previously initiated by the ISO hereunder; and (ii) billing, payment and accounting with respect to all matters arising hereunder or pursuant to a Service Agreement. Additionally, any provisions of the ISO Services Tariff or a Service Agreement which expressly survive termination or cancellation of the ISO Services Agreement or Services Tariff shall remain in effect in accordance with those provisions.

4 Market Services: Rights and Obligations

4.1 Market Services - General Rules

4.1.1 Overview

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

4.1.2 Independent System Operator Authority

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

OATT.

4.1.3 Informational and Reporting Requirements

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

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

Costs that the ISO will report as uplift include: (1) Day-Ahead and real-time Bid Production Cost guarantee payments to Generators and to Demand Side Resource aggregations; (2) Day-Ahead Bid Production Cost guarantee payments

to Suppliers that schedule Imports; (3) Day-Ahead Margin Assurance Payments; (4) cost recovery for units responding to Local Reliability Rules addressing loss of Generator gas supply; (5) Import Curtailment Guarantee Payments to Suppliers that schedule Imports in real-time; and (6) Lost Opportunity Cost payments to Suppliers of Voltage Support Service.

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

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

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

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

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

(c) commitment reason: (i) system-wide capacity need, or (ii) constraint

management, or (iii) voltage support; and

(d) commitment start time.

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

4.1.4 Scheduling Prerequisites

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

4.1.5 Communication Requirements for Market Services

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

installation and maintenance of the subject equipment and software.

4.1.6 Customer Responsibilities

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

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

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

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

4.1.7 Customer Compliance with Laws, Regulations and Orders

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

4.1.7.1 Violations of FERC's orders, rules and regulations also violate this Section 4.1.7 of the ISO Services Tariff. In particular, if FERC or a court of competent jurisdiction determines there has been a violation of FERC's

regulations related to electric energy market manipulation (see 18 C.F.R. Section 1c.2, or any successor provision thereto), such violation is also a violation of this ISO Services Tariff if such violation affects or is related to the ISO Administered Markets.

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

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

4.1.8 Commitment for Reliability

Suppliers with generating units committed by the ISO for service to ensure NYCA reliability or local system reliability, that are eligible to submit start-up and minimum generation Bids, will recover startup and minimum generation costs that were not bid, that were not known before the close of the Real-Time Scheduling Window, and that were not recovered in the Dispatch Day, provided however, eligibility to recover such additional costs shall not be available for megawatts scheduled Day-Ahead. Payment for such costs shall be determined, as if bid, pursuant to the provisions of Attachment C of this Tariff. Energy Storage Resources, Aggregations that include Withdrawal-Eligible Generator(s), and Behind-the-Meter Net Generation Resources dispatched by the ISO for service to ensure NYCA reliability or local system reliability will recover incremental energy costs that were not bid, that were not known before the close of the Real-Time Scheduling Window, and that were not recovered in the

Dispatch Day, provided however, eligibility to recover such additional costs shall not be available for megawatts scheduled Day-Ahead. Payments for securing NYCA reliability and local system reliability shall be recovered by the ISO in accordance with Rate Schedule 1 of the ISO OATT.

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

in accordance with Section 6.1.13 of Rate Schedule 1 of the ISO OATT.

Re-dispatching costs incurred as a result of reductions in Transfer Capability caused by Storm Watch ("Storm Watch Costs") shall be recovered by the ISO exclusively from Transmission Customers in Load Zone J. The ISO shall calculate Storm Watch Costs by multiplying the real-time Shadow Price of any binding constraint associated with a Storm Watch, by the higher of (a) zero; or (b) the scheduled Day-Ahead flow across the constraint minus the scheduled real-time flow across the constraint. The ISO shall charge Transmission Customers in Load Zone J, and each Transmission Customer in Load Zone J shall pay Storm Watch Costs for each Billing Period based on its Withdrawal Billing Units. The ISO shall make payments to all Transmission Customers pursuant to Section 6.1.8 of the ISO OATT to allocate the Storm Watch Costs collected from Transmission Customers in Load Zone J.

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

4.1.9.1 Eligibility for Cost Recovery

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

Island has been invoked, including that period of time required for an Eligible Unit to move into and out of compliance with a Local Reliability Rule addressing the Loss of Generator Gas Supply, shall be referred to as the "Eligibility Period."

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

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

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

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

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

The period during which combined cycle Eligible Units are performing scheduled automatic fuel swap testing, including that period of time required for an Eligible Unit to move

into and out of compliance with a Local Reliability Rule addressing the Loss of Generator Gas Supply, is an "Eligibility Period."

4.1.9.2 Variable Operating Cost Recovery

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

4.1.9.3 Additional Cost Recovery

An Eligible Unit that seeks to recover costs incurred in connection with its compliance

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

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

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

In the event that the Eligible Unit and the ISO have not come to an agreement six months

prior to the beginning of the Capability Period that the Implementation Agreement is intended to govern, then either one of them may request the assistance of the Commission's Dispute Resolution Service. If the Dispute Resolution Service agrees to provide its assistance the Eligible Unit and the ISO shall participate in whatever dispute resolution process the Dispute Resolution Service may recommend. The Commission's Dispute Resolution Service may include other stakeholders to the extent confidentiality protections are in place. If, however, there is no agreement four months prior to the beginning of the relevant Capability Period then the Eligible Unit and the ISO may each file an unexecuted Implementation Agreement for the Commission's review and acceptance.

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

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

4.1.9.4 Billing

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

Reliability Rule addressing the loss of gas supply an alternate fuel is burned pursuant to, and regardless of the relative cost of the alternate fuel compared to natural gas reflected in reference levels.

4.1.9.5 Other Provisions

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

4.1.10 Supplier Aggregations

Suppliers may aggregate individual Resources electrically located in the NYCA to provide Energy, Capacity and Ancillary Services. Demand Side Resources participating in the Emergency Demand Response Program and Aggregations of Special Case Resources shall follow the rules set forth in Services Tariff Sections 22 (Att. G) and 5.12.11, respectively. Each Aggregation shall be offered as a single unit and all bidding and offer obligations under the ISO Tariffs apply to the Aggregation, or to the Aggregator, where appropriate, not to the individual Resources that comprise the Aggregation. An Aggregation that offers a combination of Energy injections, Energy withdrawals and/or Demand Reduction must be able to offer at least 100 kW of each.

Each Aggregation must meet the minimum eligibility and performance requirements to participate in the ISO Administered Markets. Unless otherwise noted, Resources within an Aggregation are not individually required to meet the minimum eligibility and performance requirements to participate in the ISO Administered Markets. Generators with PURPA

contracts, Limited Control Run of River Resources, Behind-the-Meter Net Generation Resources, Municipally-owned Generation, System Resources and Control Area System Resources are ineligible to participate in an Aggregation. One Aggregation cannot participate in another Aggregation, however, the individual Resources within an Aggregation may switch to a new Aggregation in accordance with Services Tariff Section 4.1.10.3.

A distribution utility shall have the opportunity to review the reliability and safety impacts of each Distributed Energy Resource or group of Distributed Energy Resources that are connected to the distribution utility's electric facilities. Such review shall take place prior to each Distributed Energy Resource's enrollment in the ISO Administered Markets, and whenever there is a material modification to a Distributed Energy Resource that changes its physical or operational characteristics that were previously evaluated by the applicable distribution utility. The ISO shall collect applicable physical and operational information for each Distributed Energy Resource and provide that information to the applicable distribution utility. An Aggregator is required to provide the physical and operational characteristics identified in the Aggregation System User Guide for each Distributed Energy Resource.

The ISO may fully or partially derate an individual Resource and/or an Aggregation if the ISO or applicable distribution utility determines that a Distributed Energy Resource or group of Distributed Energy Resources presents significant risk(s) to the safe and reliable operation of the Transmission System or distribution system. The Distributed Energy Resource or group of Distributed Energy Resources will not be permitted to resume operation until the ISO, distribution utility, and Aggregator are able to resolve the identified concerns. If an individual Resource and/or group of Resources is derated, the ISO shall notify the applicable Aggregator as soon as practicable of the derate and reason for derate. Additional detail related to notification

and timing of derates is included in the ISO's Aggregation Manual.

An Aggregator may remove an individual Resource and/or Aggregation from the ISO Administered Markets upon thirty (30) days' notice to the ISO, and such removal will become effective at the beginning of a calendar month.

4.1.10.1 Aggregation Composition

Aggregations must contain at least two Resources, except that a single Demand Side Resource may participate as a single-Resource Aggregation.

The minimum capability of each individual Resource participating in an Aggregation shall be 10 kW. For the purposes of this Services Tariff Section 4.1.10.1, (i) the capability of a Demand Side Resource is the Resource's enrolled one-hour Demand Reduction capability, and (ii) the capability of a Generator is its nameplate rating.

The maximum physical injection capability for a Resource participating in an Aggregation is 20 MW. Resources with a nameplate capability greater than 20 MW may participate in an Aggregation if the ISO determines sufficient physical protection and control schemes exist to limit the injection capability of the Resource to 20 MW or less. There is no maximum Demand Reduction capability for Demand Side Resources participating in an Aggregation.

Aggregations may be comprised of a single Resource type or multiple Resource types. Except as otherwise provided in the ISO Tariffs and the ISO Procedures, Aggregations that are comprised of a single Resource type shall follow the rules associated with that Resource type (*e.g.,* an Aggregation of Energy Storage Resources shall follow the rules applicable to Energy Storage Resources). Aggregated (i) Intermittent Power Resources, (ii) Energy Limited

Resources, (iii) Capacity Limited Resources, or (iv) Limited Energy Storage Resources shall constitute a single Resource type Aggregation only when the individual Resources in the Aggregation have the same Intermittent, energy limiting, or capacity limiting characteristic (*e.g.,* an Aggregation of only solar Resources, or an Aggregation of only pumped storage Resources). Provided, however, that Aggregations with multiple, different types of Intermittent Power Resources, Energy Limited Resources, Capacity Limited Resources, and Limited Energy Storage Resources shall follow the rules associated with DER Aggregations.

Aggregations that are comprised of more than one Resource type, and Aggregations comprised of only Demand Side Resources shall follow the rules associated with DER Aggregations.

Aggregations that include at least one Withdrawal-Eligible Generator may submit Bids to withdraw Energy. For the purpose of measuring Aggregation compliance with Base Point Signals, Aggregations that include at least one Withdrawal-Eligible Generator will be measured based on their net performance; that is, Energy injections and Demand Reductions will be reduced by Energy withdrawals.

When an Aggregation contains one or more Energy Storage Resources, and the applicable Load Serving Entity requires the Energy Storage Resource to also pay a retail rate for its charging withdrawals, all Energy Storage Resources in the Aggregation shall be customers of the same Load Serving Entity and pay the Load Serving Entity's applicable retail rate. An Aggregation that includes one or more Energy Storage Resources that are required to pay a retail rate for its charging withdrawals is subject to the Services Tariff Section 7.2.8 settlement rules for Energy Storage Resources.

Aggregators shall not offer any Resource as part of an Aggregation that is participating in

the ISO Administered Markets in a different Aggregation or as an individual Resource.

Aggregators shall ensure that Aggregation operating parameters submitted to the ISO are consistent with the combined operating parameters and applicable interconnection agreements of each individual Resource in the Aggregation.

4.1.10.2 Aggregation Electrical Location

The ISO shall establish a set of Transmission Nodes in the New York Control Area at which individual Resources may aggregate. Each Transmission Node shall be identified in the ISO Procedures. The ISO shall consult with the appropriate Member System prior to identifying a Transmission Node in accordance with ISO Procedures. Aggregators shall identify, after consultation with the interconnecting utility, the Transmission Node for each Aggregation. All Resources in an Aggregation must be electrically located in the New York Control Area, and electrically connected to the same ISO-identified Transmission Node. Multiple Aggregators may each enroll one or more Aggregations at a Transmission Node.

The ISO may modify the set of Transmission Nodes from time to time due to conditions on the New York State Transmission System and the underlying distribution systems changing over time. The ISO shall also review and update (if needed) the identified Transmission Nodes on an annual basis, and will post a notice of any changes to the identified Transmission Nodes at least ninety (90) days prior to the beginning of the Capability Year. Changes to the set of Transmission Nodes shall take effect on the first day of the Capability Year. Aggregators shall certify, in accordance with ISO Procedures, that Aggregations affected by changes to Transmission Nodes meet all requirements of this Section pursuant to ISO Procedures.

4.1.10.3 Resources Entering and Changing Aggregations

Subject to the requirement that all of the Resources in an Aggregation must be

electrically connected to the same ISO-identified Transmission Node, an individual Resource may enter an Aggregation for the first time or leave its current Aggregation and join a new Aggregation to be effective at the start of a calendar month, but must provide at least thirty (30) calendar days notice of its intent to enter or change Aggregations. Registration of Resources that leave or join an Aggregation shall be completed in accordance with ISO Procedures. The ISO must approve all Resource registrations before the Resource is allowed to participate in an Aggregation.

Additional rules for Resources changing Aggregations, that participate in the ICAP market are located in Services Tariff Section 5.12.13.1.

4.1.10.4 Aggregation Metering

Each Aggregation must meet the applicable metering standards identified in the ISO's Tariffs and in ISO Procedures. Aggregators may choose to have an ISO-authorized Meter Services Entity or the applicable Member System provide Aggregation metering services for wholesale market participation. *See* Services Tariff § 13.

Real-time telemetry data and revenue-quality meter data shall be submitted for each Aggregation. Real-time telemetry for DER Aggregations shall consist of four parts: (i) Energy injections, (ii) Energy withdrawals by Withdrawal Eligible Generators, (iii) Demand Reductions, and (iv) the sum of (i), (ii) and (iii). Revenue-quality meter data for each DER Aggregation shall consist of three parts: (i) Energy injections; (ii) Energy withdrawals by Withdrawal-Eligible Generators; and (iii) Demand Reductions. Aggregations of other Resource types shall submit meter data in accordance with Services Tariff Section 13 and the ISO Procedures.

4.1.10.5 Qualification Requirements for Aggregators

Aggregators must be Customers. Aggregators must (i) comply with the registration requirements set forth in Services Tariff Section 9, and the ISO Procedures; (ii) designate one or more contact persons to receive ISO communications; and (iii) comply with the metering requirements set forth in Services Tariff Section 13 and the associated ISO Procedures.

4.1.11 Dual Participation

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

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

4.2 Day-Ahead Markets and Schedules

4.2.1 Day-Ahead Load Forecasts, Bids and Bilateral Schedules

4.2.1.1 General Customer Forecasting and Bidding Requirements

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

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

b. Bids to supply Ancillary Services;

c. Requests for Bilateral Transaction schedules;

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

e. 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, the HTP Scheduled Line, or the Champlain Hudson Power Express MTF.

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 if it issues to CSR Generators.

Self-Managed Energy Storage Resources, Self-Managed 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, Self-Managed 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. For a Combined Cycle Gas Turbine Generator with Duct-Firing Capability that has opted for the Limiting Participation Flag, the Participation Limit and the emergency response rate will determine the quantity of 10-Minute Reserves that the Resource is capable of providing. Offers to provide Regulation Service and Operating Reserves must comply with the rules set forth in Rate Schedules 3 and 4 of this ISO Services Tariff. If a Supplier that is eligible to provide Operating Reserves does not submit a Day-Ahead Availability Bid for Operating Reserves, its Day-Ahead Bid shall be rejected in its entirety. A Behind-the-Meter Net Generation Resource that is comprised of more than one generating unit, 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. Aggregations may only qualify to offer the Ancillary Services that all individual Resources in the Aggregation are qualified to provide. 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 and single resource type Aggregations that depend solely 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.

4.2.1.4 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, Energy Storage Resources, and Aggregations as already being committed and available to be scheduled. Pursuant to ISO Procedures, the ISO may schedule any Resource to run above its UOL_N up to the level of its UOL_E. In cases in which the sum of all Bilateral Schedules, excluding Bilateral Schedules for Transactions with Trading Hubs 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. 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.

4.3 In-Day Scheduling Changes

Prior to the Capability Period beginning May 1, 2025, after the Day-Ahead schedule is published, the ISO shall normally grant requests by Capacity Limited Resources and Energy Limited Resources for reductions from Day-Ahead schedules to their UOL_Ns for any hour(s) in which they are scheduled above their UOL_Ns. However, the ISO may schedule such Resources to provide Energy in the Real-Time Market in an amount up to its Day-Ahead schedule during the relevant hour(s) at a price no higher than the relevant Day-Ahead offer price when it is needed to prevent or to address an Emergency.

Beginning with the Capability Period beginning May 1, 2025, after the Day-Ahead schedule is published, the ISO shall normally grant requests by Energy Limited Resources for reductions from Day-Ahead schedules to their UOL_{NS} for any hour(s) in which they are scheduled above their UOL_{NS}. However, the ISO may schedule such Resources to provide Energy in the Real-Time Market in an amount up to its Day-Ahead schedule during the relevant hour(s) at a price no higher than the relevant Day-Ahead offer price when it is needed to prevent or to address an Emergency.

The ISO will not recall Energy produced by a Generator serving External Load to the extent that the Generator is not providing Installed Capacity (and has not indicated that it wishes to qualify as a provider of Installed Capacity) in the NYCA. The ISO shall take action, including manual intervention, to schedule Export Transactions from Generators that have Available Generating Capacity and that have supplied installed Capacity to entities serving Load located in an External Control Area when the External Control Area issues a notification requiring such Generators to supply Energy, provided however, that any Transaction may be Curtailed in response to the invocation of Transmission Loading Relief procedures by the ISO or by operators

of other Control Areas. Energy from non-Installed Capacity providers in New York which is being Supplied outside the NYCA could be purchased by the ISO, pursuant to ISO Procedures, should an emergency exist in the NYCA, provided however that Energy from Generators that have supplied installed Capacity to entities serving Load located in an External Control Area that are responding to a notification by the External Control Area that requires such Generators to supply Energy, may not be purchased by the ISO should a capacity resource emergency exist in the NYCA.

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, 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.

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.

Self-Managed Energy Storage Resources, Self-Managed 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, Self-Managed 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.

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. 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. 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).

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

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

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

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

External Bilateral Transactions shall also be subject to the provisions of Section 16, Attachment J of the ISO OATT.

4.4.1.2.3 Self-Commitment Requests

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

4.4.1.2.4 ISO-Committed Fixed

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

RTC shall schedule ISO-Committed Fixed Generators.

4.4.1.3 External Transaction Scheduling

RTC15 will schedule External Transactions on an hourly basis as part of its development of a co-optimized least-bid cost Real-Time Commitment. For External Transactions that are

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

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

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

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

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

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

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

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

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

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

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

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

(viii) Schedule ISO-Committed Fixed Resources.

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

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

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

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

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

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

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

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

(viii) Schedule ISO-Committed Fixed Resources.

4.4.1.5 External Transaction Settlements

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

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

4.4.2 Real-Time Dispatch

4.4.2.1 Overview

The Real-Time Dispatch will make dispatching decisions, send Base Point Signals to Internal Generators and 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. The Beginning Energy Level of an Energy Storage Resource or of an Aggregation comprised only of Energy Storage Resources 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. Combined Cycle Gas Turbine Generators with Duct-Firing Capability that have opted for the Limiting Participation Flag will not be dispatched beyond the specified Participation Limit, unless such a Resource is already above its Participation Limit, in which case it will not be dispatched to or below than its Participation Limit, at the time that RTD-CAM is activated.

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

4.4.3.1 RTD-CAM Modes

4.4.3.1.1 Reserve Pickup

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

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

The ISO will have discretion to classify a reserve pickup as a “large event” or a “small event.” In a small event the ISO will have discretion to reduce Base Point Signals in order to reduce transmission line loadings. The ISO will not ordinarily have this discretion in large events, except that it may determine Energy schedules that satisfy Operating Reserve energy

sustainability requirements for Energy Storage Resources. The distinction also has significance with respect to a Supplier's eligibility to receive Bid Production Cost guarantee payment in accordance with Section 4.6.6 and Attachment C of this ISO Services Tariff.

4.4.3.1.2 Maximum Generation Pickup

The ISO will enter this RTD-CAM mode when an Emergency makes it necessary to maximize Energy production in one or more location(s), i.e., Long Island, New York City, Southeastern New York, East of Central East and/or NYCA-wide. RTD-CAM will produce schedules directing all Generators 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. RTD-CAM will produce schedules directing each Combined Cycle Gas Turbine Generator with Duct-Firing Capability that has not opted for the Limiting Participation Flag, located in a targeted location, to increase production at the normal response rate corresponding to the Generator's output level at the time when RTD-CAM was activated, until reaching its UOL_E, and to continue to operate at that level until instructed otherwise. RTD-CAM will produce schedules directing each Combined Cycle Gas Turbine Generator with Duct-Firing Capability, that has opted for the Limiting Participation Flag, located in a targeted location, to increase production at the normal response rate corresponding to the Generator's output level at the time when RTD-CAM was activated, until: (i) reaching its Participation Limit, and to continue to operate at that level until instructed otherwise, if the Generator's output level was below or equal to the Participation Limit at the time when RTD-CAM was activated or (ii) reaching its UOL_E, and to continue to operate at that level until instructed otherwise, if the Generator's output level was above its Participation Limit at the time RTD-CAM was activated.

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			✓			✓		
HQ_CHPE_GEN	323851	Champlain Hudson Power Express MTF		✓			✓*+ (See Notes)	✓	
HQ_CHPE_LOAD	356515	Champlain Hudson Power Express MTF		✓			✓*+ (See Notes)	✓	
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)	✓	

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)
PJM_LOAD_VFT_PROXY	355723	Linden VFT Scheduled Line	✓			✓	✓* (See Notes)	✓	
PJM_HTP_GEN	323702	HTP Scheduled Line	✓			✓	✓* (See Notes)	✓	
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.
+ The Champlain Hudson Power Express MTF, Neptune Scheduled Line and HTP Scheduled Line are all unidirectional transmission facilities. Only Imports of Energy to the NYCA can be scheduled over these facilities.

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.

4.5 Real-Time Market Settlements

Transmission Customers and Customers taking service under this ISO Services Tariff or the ISO OATT, shall be subject to the Real-Time Market Settlement. All withdrawals, injections, and Demand Reductions not scheduled on a Day-Ahead basis, including Real-Time deviations from any Day-Ahead External Transaction schedules, shall be subject to the Real-Time Market Settlement. Transmission Customers not taking service under this Tariff shall be subject to balancing charges as provided for under the ISO OATT. Settlements with Suppliers scheduling service from External Suppliers to the LBMP Market or to External Loads from the LBMP Market will be based upon scheduled withdrawals or injections. Real-Time Market Settlements for Energy provided by Resources supplying Regulation Service or Operating Reserves shall follow the rules which are described in Rate Schedules 15.3 and 15.4, respectively.

For the purposes of this section, the scheduled output of each of the following Generators in each RTD interval in which it has offered Energy shall retroactively be set equal to its actual output in that RTD interval:

(i) Generators, except for the Generator of a Behind-the-Meter Net Generation Resource and Generators in an Aggregation, providing Energy under contracts executed and effective on or before November 18, 1999 (including PURPA contracts) in which the power purchaser does not control the operation of the supply source but would be responsible for penalties for being off-schedule, with the exception of Generators under must-take PURPA contracts executed and effective on or before November 18, 1999 who have not provided telemetering to their local TO and historically have not been eligible to participate in the NYPP

market, which will continue to be treated as TO Load modifiers under the ISO-administered markets;

(ii) Existing topping turbine Generators and extraction turbine Generators producing electric Energy resulting from the supply of steam to the district steam system located in New York City (LBMP Zone J) in operation on or before November 18, 1999 and/or Generators utilized in replacing or repowering existing steam supplies from such units (in accordance with good engineering and economic design) that cannot follow schedules, up to a maximum total of 533 MW of such units.

This procedure shall not apply to Behind-the-Meter Net Generation Resources, Aggregations or a Generator for those hours it has used the ISO-Committed Flexible or Self-Committed Flexible bid mode.

In Sections 4.5.1, 4.5.2, 4.5.3, and 4.5.4 of this Tariff, references to "scheduled" Energy injections and withdrawals shall encompass injections, including Demand Reductions, and withdrawals that are scheduled Day-Ahead, unless otherwise noted, as well as injections and withdrawals that occur in connection with real-time Bilateral Transactions. In Sections 4.5.2 and 4.5.3 of this Tariff, references to Energy Withdrawals and Energy Injections shall not include Energy Withdrawals or Energy Injections in Virtual Transactions, or Energy Withdrawals or Energy Injections at Trading Hubs. Generators, including Limited Energy Storage Resources and Aggregations, that are providing Regulation Service shall not be subject to the real-time Energy market settlement provisions set forth in this Section, but shall instead be subject to the Energy settlement rules set forth in Rate Schedule 15.3 of this ISO Services Tariff.

4.5.1 Settlement for Customers Scheduled To Sell Energy in Virtual Transactions in Load Zones

The Actual Energy Injection in a Load Zone by a Customer scheduled Day-Ahead to sell Energy in a Virtual Transaction is zero and the Customer shall pay a charge for the Energy imbalance equal to the product of: (a) the Real-Time LBMP calculated in that hour for the applicable Load Zone; and (b) the scheduled Day-Ahead Energy Injection of the Customer for that Hour in that Load Zone.

4.5.2 Real-Time Market Settlements for Energy

4.5.2.1 General Rules for Suppliers

A Supplier, which is not a DER Aggregation, shall pay or be paid for Energy imbalance to account for differences between Actual Energy Injections, compensable Demand Reductions, real-time Energy schedules and Day-Ahead Energy schedules.

A DER Aggregation shall pay or be paid for Energy imbalance based on the (1) Actual Energy Injections, real-time Energy schedules, Day-Ahead Energy schedules, and (2) all compensable Demand Reductions eligible for payment at the applicable LBMP pursuant to Services Tariff Section 4.5.7.

A Generator or Aggregation that is not following Base Point Signals shall not be compensated for Energy in excess of its Real-Time Scheduled Energy injection if its applicable upper operating limit has been reduced below its bid-in upper operating limit by the ISO in order to reconcile the ISO's dispatch with the Generator or Aggregation's actual output, or to address reliability concerns.

If the Energy provided by a Supplier over an RTD interval is less than the Supplier's Day-Ahead Energy schedule, and if the Supplier reduced the Energy it provides in response to instructions by the ISO or a Transmission Owner that were issued in order to maintain a secure

and reliable dispatch, the Supplier may be entitled to a Day-Ahead Margin Assurance Payment, pursuant to Attachment J of this ISO Services Tariff.

4.5.2.1.1 Supplier Payments when LBMP is Positive

When the LBMP calculated in that RTD interval at the applicable Generator or Aggregation's bus is positive, the Supplier payment shall be calculated as follows:

Supplier payment for Energy injections and withdrawals = ((MIN(AE_{iu},RTS_{iu}) – DAS_{hu}) * $LBMP_{iu}^{RT}$) * $\frac{S_i}{3600}$

Where:

AE_{iu} = (1) average Actual Energy Injection by Supplier *u* in interval *i* expressed in terms of MW; or (2) average Actual Energy Withdrawal by an Energy Storage Resource *u* or Aggregation *u* that includes Energy Storage Resource(s) in interval *i* expressed in terms of MW;

RTS_{iu} = (1) real-time Energy scheduled by Supplier *u* in interval *i* plus Compensable Overgeneration; or (2) real-time Energy scheduled for withdrawal by Energy Storage Resource *u* or Aggregation *u* that includes Withdrawal-Eligible Generator(s) in interval *i* plus 3% of the absolute value of the Energy Storage Resource's or Aggregation's Lower Operating Limit; or (3) average Actual Energy Withdrawal by an Energy Storage Resource *u* or Aggregation *u* that includes Withdrawal-Eligible Generator(s) in interval *i* when it has been designated as operating Out-of-Merit to withdraw at the request of a Transmission Owner or the ISO;

DAS_{hu} = Day-Ahead Energy schedule for Supplier *u* in hour *h* containing interval *i*;

$LBMP_{iu}^{RT}$ = real-time price of Energy at the location of Supplier *u* in interval *i*;

S_i = number of seconds in RTD interval *i*;

Supplier payment for Demand Reductions =

(MIN(ADR_{iu} , MAX(RTS_{iu} – AE_{iu} , 0)) * $LBMP_{iu}^{RT}$) * $\frac{S_i}{3600}$

Where:

ADR_{iu} = average Actual Demand Reduction that is eligible for Energy payments pursuant to Services Tariff Section 4.5.7 by Supplier *u* in interval *i*, the ADR_{iu} term will be set to

zero if the Actual Demand Reduction is not eligible for Energy payments pursuant to Services Tariff Section 4.5.7;

The remaining variables are defined above in this Section 4.5.2.1.1.

4.5.2.1.2 Supplier Payments when LBMP is negative, during a large event reserve pickup, during a maximum generation pickup, or during a Transmission Owner initiated reserve pickup

When: (1) the LBMP calculated in that RTD interval at the applicable Generator or Aggregation bus is negative; or (2) the ISO initiates a large event reserve pickup or a maximum generation pickup under RTD-CAM that applies to the Load Zone where the Generator or Aggregation is located; or (3) a Transmission Owner initiates a reserve pickup in accordance with a Reliability Rule, including a Local Reliability Rule, then the Supplier payment shall be calculated as follows:

Supplier payment for Energy injections and withdrawals = $((AE_{iu} - DAS_{hu}) * LBMP_{iu}^{RT}) * \frac{S_i}{3600}$

Where:

The variables are defined above in this Section 4.5.2.1.1.

Supplier payment for Demand Reductions = $ADR_{iu} * LBMP_{iu}^{RT} * \frac{S_i}{3600}$

Where:

ADR_{iu} = average Actual Demand Reduction by Supplier u in interval i;

The remaining variables are defined above in Section 4.5.2.1.1.

4.5.2.1.3 Supplier Payments for Imports

Suppliers scheduling Imports shall pay or be paid for Energy imbalance to account for differences between real-time Energy schedules and Day-Ahead Energy schedules. For an

Import to the LBMP Market that is only scheduled in the Real-Time Market, or to the extent it is scheduled to supply additional or less Energy to the LBMP Market in real-time than it was scheduled to supply Day-Ahead, the Supplier payment shall be calculated as follows:

Supplier payment for Imports = $((\text{RTS}_{\text{iup}} - \text{DAS}_{\text{hup}}) * LBMP_{ip}^{RT}) * \frac{S_i}{3600}$

Where:

RTS_{iup} = real-time Energy scheduled for injection by Supplier *u* in interval *i* at Proxy Generator Bus *p*;

DAS_{hup} = Day-Ahead Energy schedule for Supplier *u* in hour *h* containing interval *i* at Proxy Generator Bus *p*;

$LBMP_{ip}^{RT}$ = real-time price of Energy at the Point of Receipt *p* (*i.e.*, the Proxy Generator Bus) in interval *i*;

S_i = number of seconds in RTD interval *i*;

4.5.2.2 Failed Transactions

If an Energy injection scheduled by RTC at a Proxy Generator Bus fails in the ISO's checkout process and the checkout failure occurred for reasons within the Supplier's or Transmission Customer's control, it will be required to pay the "Financial Impact Charge" described below. The ISO will determine whether the Transaction associated with an injection failed for reasons within a Supplier's or Transmission Customer's control.

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

If a Wheel Through fails for reasons within a Supplier's or Transmission Customer's control, the Financial Impact Charge will equal the sum of the Financial Impact Charge described in this section and the Financial Impact Charge described below in Section 4.5.3.2.

All Financial Impact Charges collected by the ISO shall be used to reduce the charges assessed under Rate Schedule 1 of this ISO Services Tariff. In the event that the Energy injections for an Import scheduled by RTC or RTD, at a Proxy Generator Bus is Curtailed at the request of the ISO, and (i) the real-time Energy Profile MW is equal to or greater than the Day-Ahead Energy Schedule for that interval, and (ii) the real-time Decremental Bid is less than or equal to the default real-time Decremental Bid amount as established by ISO procedures, then the Supplier or Transmission Customer that is subjected to the Curtailment, in addition to the charge for Energy Imbalance, shall be eligible to receive an Import Curtailment Guarantee Payment for its curtailed Import pursuant to Attachment J of this ISO Services Tariff.

4.5.2.3 Capacity Limited Resources and Energy Limited Resources

Prior to the Capability Period beginning May 1, 2025, for any hour in which: (i) a Capacity Limited Resource or an Aggregation comprised entirely of Capacity Limited Resources is scheduled to supply Energy, Operating Reserves, or Regulation Service in the Day-Ahead Market; (ii) the sum of its schedules to provide these services exceeds its bid-in upper operating limit; (iii) the Capacity Limited Resource or Aggregation comprised entirely of Capacity Limited Resources requests a reduction for Capacity limitation reasons; and (iv) the ISO reduces the Capacity Limited Resource's or the Aggregation comprised entirely of Capacity Limited Resources upper operating limit to a level equal to, or greater than, its bid-in upper operating limit; the imbalance charge for Energy, Operating Reserve Service or Regulation Service imposed on that Capacity Limited Resource or Aggregation comprised entirely of Capacity

Limited Resources for that hour for its Day-Ahead Market obligations above its Capacity limited upper operating limit shall be equal to the product of: (a) the Real-Time price for Energy, Operating Reserve Service and Regulation Capacity; and (b) the Capacity Limited Resource's or the Aggregation comprised entirely of Capacity Limited Resources Day-Ahead schedule for each of these services minus the amount of these services that it has an obligation to supply pursuant to its ISO-approved schedule. Prior to the Capability Period beginning May 1, 2025, when a Capacity Limited Resource's or the Aggregation comprised entirely of Capacity Limited Resources Day-Ahead obligation above its Capacity limited upper operating limit is balanced as described above, any real-time variation from its obligation pursuant to its Capacity limited schedules shall be settled pursuant to the methodology set forth in Section 4.5.2.1. After April 30, 2025, Resources shall no longer be able to participate as Capacity Limited Resources.

For any day in which: (i) an Energy Limited Resource or an Aggregation comprised entirely of Capacity Limited Resources is scheduled to supply Energy, Operating Reserves or Regulation Service in the Day-Ahead Market; (ii) the sum of its schedules to provide these services exceeds its bid-in Normal Upper Operating Limit; (iii) the Energy Limited Resource or the Aggregation comprised entirely of Capacity Limited Resources requests a reduction for Energy limitation reasons; and (iv) the ISO reduces the Energy Limited Resource's Day-Ahead Emergency Upper Operating Limit to a limit no lower than the Normal Upper Operating Limit; the Resource may be eligible to receive a Day-Ahead Margin Assurance Payment pursuant to Attachment J of this ISO Services Tariff.

4.5.3 Real-Time Market Settlements for Energy Withdrawals Other Than in Virtual Transactions

4.5.3.1 General Rules

A Customer (other than a Generator that is eligible to withdraw Energy) shall pay or be paid for Energy imbalance to account for differences between Actual Energy Withdrawals over an RTD interval and its Energy withdrawals scheduled Day-Ahead. The ISO shall charge the Customer as follows for each applicable Load Zone:

Customer Charge = $((\text{AEW}_{icz} - \text{DAS}_{hcz}) * LBMP_{iz}^{RT}) * \frac{S_i}{3600}$

Where:

AEW_{icz} = Actual Energy Withdrawal by Customer *c* in Load Zone *z* in interval *i*;

DAS_{hcz} = Day-Ahead scheduled Energy withdrawals by Customer *c* in Load Zone *z* in hour *h* containing interval *i*;

$LBMP_{iz}^{RT}$ = real-time price of Energy for Load Zone *z* in interval *i*;

S_i = number of seconds in RTD interval i;

If the Generator of a Behind-the-Meter Net Generation Resource is not able to serve the Resource's Host Load at any time, any resulting Actual Energy Withdrawals that serve the Host Load will be charged to the Load Serving Entity responsible for serving the Behind-the-Meter Net Generation Resource.

4.5.3.1.1 Customer Settlements for Exports

Customers scheduling Exports shall pay or be paid for Energy imbalance to account for differences between real-time Energy schedules and Day-Ahead Energy schedules. For an Export from the LBMP Market that is only scheduled in the Real-Time Market, or to the extent it

is scheduled to withdraw additional or less Energy from the LBMP Market in real-time than it was scheduled to withdraw Day-Ahead, the ISO shall charge the Customer as follows:

Customer Charge for Exports = $((RTS_{iup} - DAS_{hup}) * LBMP_{ip}^{RT}) * \frac{S_i}{3600}$

Where:

RTS_{iup} = real-time Energy scheduled for withdrawal by Customer *u* in interval *i* at Proxy Generator Bus *p*;

DAS_{hup} = Day-Ahead Energy schedule for Customer *u* in hour *h* containing interval *i* at Proxy Generator Bus *p*;

$LBMP_{ip}^{RT}$ = real-time price of Energy at the Point of Delivery *p* (*i.e.*, the Proxy Generator Bus) in interval *i*;

S_i = number of seconds in RTD interval i;

4.5.3.2 Failed Transactions

If an Energy withdrawal at a Proxy Generator Bus scheduled by RTC fails in the ISO's checkout process and the checkout failure occurred for reasons within the Supplier's or Transmission Customer's control, it will be required to pay the "Financial Impact Charge" described below. The ISO will determine whether the Transaction associated with a withdrawal failed for reasons within a Supplier's or Transmission Customer's control.

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

If a Wheel Through fails for reasons within a Supplier's or Transmission Customer's control, the Financial Impact Charge will equal the sum of the Financial Impact Charge described in this subsection and the Financial Impact Charge described above in Section 4.5.2.2.

All Financial Impact Charges collected by the ISO shall be used to reduce the charges assessed under Rate Schedule 15.1 of this ISO Services Tariff.

4.5.4 Settlement for Customers Scheduled To Purchase Energy in Virtual Transactions in Load Zones

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

4.5.5 Settlement for Trading Hub Energy Owner when POI is a Trading Hub

Each Trading Hub Energy Owner who bids a Bilateral Transaction into the Real-Time Market with a Trading Hub as its POI and has its schedule accepted by the ISO will pay the product of: (a) the hourly integrated Real-Time LBMP for the Load Zone associated with that Trading Hub; and (b) the Bilateral Transaction scheduled MW.

4.5.6 Settlement for Trading Hub Energy Owner when POW is a Trading Hub

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

4.5.7 Settlement for Demand Reductions

4.5.7.1 Monthly Net Benefits Test

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

The ISO shall promptly post corrections, where necessary, to the Monthly Net Benefit Threshold. Corrections shall only apply to errors in conducting the calculations described above and/or in posting the properly calculated Monthly Net Benefit Threshold. Corrections shall not include recalculations based on changes in gas prices.

4.5.7.2 Settlement Eligibility for Demand Reductions

A DER Aggregation may offer into the Day-Ahead Market or Real-Time Market below the Monthly Net Benefit Threshold. However, when a DER Aggregation receives a real-time Energy schedule, and the Real-Time LBMP calculated in that RTD interval for the applicable Transmission Node is less than the Monthly Net Benefit Threshold price, Demand Reductions by the DER Aggregation shall not be eligible for Energy payments, Day Ahead Margin Assurance Payments or Bid Production Cost guarantee payments otherwise available under this Services

Tariff. Provided, however, if the DER Aggregation is dispatched by the ISO or Transmission Owner to meet NYCA or local system reliability, the Demand Reductions shall be eligible for Energy payments. The DER Aggregation may also be eligible for Day Ahead Margin Assurance Payments pursuant to Attachment J of this ISO Services Tariff and Bid Production Cost guarantee payments pursuant to Attachment C of this ISO Services Tariff.

4.5.8 Performance Tracking

The ISO shall use a Performance Tracking System to compute the difference between the Energy actually supplied and the Energy scheduled by the ISO for all Suppliers located within the NYCA and shall use it to measure compliance with criteria associated with the provision of Energy and Ancillary Services as set forth in the ISO Procedures. The Performance Tracking System shall also be used to report metrics for Loads.

4.6 Payments

4.6.1 Payments to Suppliers of Regulation Service

Suppliers of Regulation Service shall receive a payment that is calculated pursuant to Rate Schedule 15.3 of this ISO Services Tariff

4.6.2 Payments to Suppliers of Reactive Supply and Voltage Support Service ("Voltage Support Service")

Suppliers of Voltage Support Service shall receive a Voltage Support Service payment in accordance with the criteria and formula in Rate Schedule 15.2.

4.6.3 Payments to Suppliers for Operating Reserves

Suppliers of each type of Operating Reserve will receive payments for each MW of Operating Reserve that they provide, as requested by the ISO, pursuant to Rate Schedule 15.4.

Additionally, Generators and Aggregations providing Operating Reserves shall receive a payment for Energy injections when the ISO requests Energy under a reserve activation. The Energy payment shall be calculated as the product of: (a) the Energy provided; and (b) the Real-Time Market LBMP.

4.6.4 Payments to Generators for Black Start Capability

Black Start Capability providers shall receive a payment for Black Start Capability as set forth in Rate Schedule 15.5.

4.6.5 Day-Ahead Margin Assurance Payments

A Supplier that is scheduled in the Day-Ahead Market to provide Energy, Regulation Service, or Operating Reserves may be eligible to receive a Day-Ahead Margin Assurance Payment pursuant to Attachment J of this ISO Services Tariff.

4.6.6 Bid Production Cost Guarantee Payments

4.6.6.1 Day-Ahead BPCG for Generators

The ISO shall determine if a Supplier eligible under Section 18.2.1 of Attachment C of this ISO Services Tariff for a Day-Ahead Bid Production Cost guarantee payment will not recover its Day-Ahead Regulation Capacity Bid, Operating Reserves Bid, or its Minimum Generation Bid, Start-Up Bid, and Incremental Energy Bid for Energy scheduled in the Day-Ahead Market, including Energy provided by the capacity scheduled for Regulation Service, through Day-Ahead LBMP revenue, Day-Ahead Imputed LBMP Revenue and net Day-Ahead Ancillary Services revenues for Voltage Support Service, Regulation Service, and synchronized Operating Reserves. Such determination shall be made for an entire Day-Ahead Market day, and such determination shall be made separately for each Generator. On the basis of such determination (and subject to any mitigation that may apply) the ISO shall pay a Day-Ahead BPCG to the Supplier pursuant to Section 18.2 of Attachment C to this ISO Services Tariff.

4.6.6.2 Day-Ahead BPCG for Imports

The ISO shall determine if a Supplier supplying an Import and eligible under Section 18.3.1 of Attachment C of this ISO Services Tariff for a Day-Ahead Bid Production Cost guarantee payment will not recover its Day-Ahead Decremental Bid through Day-Ahead LBMP revenue and Day-Ahead Imputed LBMP Revenue. Such determination shall be made for an entire Day-Ahead Market day and such determination shall be made separately for each Import transaction. On the basis of such determination, the ISO shall pay a Day-Ahead Bid Production Cost guarantee payment to the Supplier pursuant to Section 18.3 of Attachment C of this ISO Services Tariff.

4.6.6.3 Real-Time BPCG for Generators in RTD Intervals Other than Supplemental Event Intervals

The ISO shall determine if a Supplier eligible under Section 18.4.1 of Attachment C of this ISO Services Tariff for a real-time Bid Production Cost guarantee payment will not recover its real-time Regulation Capacity Bid, Regulation Movement Bid, Operating Reserves Bid, or its Minimum Generation Bid, Start-Up Bid, and Incremental Energy Bid for Energy that was not scheduled in the Day-Ahead Market, including Energy provided by the capacity scheduled for Regulation Service, through real-time LBMP revenue, real-time Imputed LBMP Revenue and net real-time Ancillary Services revenues for Voltage Support Service, Regulation Service, and synchronized Operating Reserves. Such determination shall be made for an entire Dispatch Day (except for Supplemental Event Intervals). Such determination shall be made separately for each Generator. On the basis of such determination, and subject to any mitigation that may apply, the ISO shall pay a real-time Bid Production Cost guarantee payment to the Supplier pursuant to Section 18.4 of Attachment C to this ISO Services Tariff and, as applicable, Section 15.3.

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

4.6.6.4 BPCG for Generators for Supplemental Event Intervals

The ISO shall determine if a Supplier eligible under Section 18.5.1 of Attachment C of this ISO Services Tariff for a Bid Production Cost guarantee payment for a Supplemental Event Interval will not recover its real-time Regulation Capacity Bid, Regulation Movement Bid, Operating Reserves Bid, or its Minimum Generation Bid and Incremental Energy Bid for Energy that was not scheduled Day-Ahead, including Energy provided by the capacity scheduled for

Regulation Service, through real-time LBMP revenue, real-time Imputed LBMP Revenue and net real-time Ancillary Services revenues for Voltage Support Service, Regulation Service, and Operating Reserves in that interval. Such determination shall be made separately for each Supplemental Event Interval, and such determination shall be made separately for each Generator. On the basis of such determination, the ISO shall pay a Bid Production Cost guarantee payment to the Supplier for a Supplemental Event Interval pursuant to Section 18.5 of Attachment C of this ISO Services Tariff.

4.6.6.5 Real-Time BPCG for External Transactions

External Transactions are not eligible to receive Bid Production Cost guarantee payments in the Real-Time Market pursuant to Section 18.6 of Attachment C of this ISO Services Tariff.

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

The ISO shall pay a Supplier eligible under Section 18.7.1 of Attachment C of this ISO Services Tariff for a Bid Production Cost guarantee payment for a long start-up time Generator (i.e., a Generator that cannot be scheduled by SCUC to start up in time for the next Dispatch Day) whose start is aborted by the ISO prior to its dispatch for that portion of its Start-Up Bid that corresponds to that portion of its start-up sequence that it completed prior to being aborted. Such determination shall be made for an entire Dispatch Day, and such determination shall be made separately for each long start-up time Generator. On the basis of such determination, the ISO shall pay a Bid Production Cost guarantee payment to the Supplier pursuant to Section 18.7 of Attachment C of this ISO Services Tariff.

4.6.6.7 BPCG for Special Case Resources

The ISO shall determine if a Supplier eligible under Section 18.9.1 of Attachment C of this ISO Services Tariff for a Bid Production Cost guarantee payment for a Special Case Resource will not recover its Minimum Payment Nomination through real-time LBMP revenues. Such determination shall be made for an entire Dispatch Day, and such determination shall be made separately for each Special Case Resource. On the basis of such determination, the ISO shall make a Bid Production Cost guarantee payment to the Supplier pursuant to Section 18.9 of Attachment C of this ISO Services Tariff.

4.7 Procurement of Station Power

A Generator may self-supply Station Power in accordance with the following provisions.

4.7.1 A Generator may self supply Station Power during any calendar month when either:

4.7.1.1 Its net output for that month is positive; or

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

4.7.1.2.1 If an entity owns a portion of a jointly owned Generator it may remotely self-supply its other Generators up to the amount of its entitlement to Energy from the jointly-owned Generator provided that: (A) the entity has the right to call upon that Energy for its own use; and (B) the Energy entitlement is not characterized as a sale from the jointly owned Generator to any of its joint owners.

4.7.2 A Generator's net output for the month may be positive because either:

4.7.2.1 The Generator is physically supplying Energy for its Station Power needs, using its own facilities, and without using facilities that are owned by any Transmission Owner; or

4.7.2.2 The Generator's Station Power requirements for the month, including all Energy received for use as Station Power, regardless of its voltage or the metering point

of receipt, are less than the amount of Energy that the Generator injects into the New York State Power System for the month.

4.7.3 The determination of net output under this Section 4.7 shall apply only to determine whether the Generator self-supplied Station Power during the month and will not affect the price of Energy sold or consumed by the Generator at any bus during any hour during the month.

4.7.4 When a Generator has positive net output for an interval and is delivering Energy into the New York State Power System, it will be paid the Real-Time or Day-Ahead LBMP at its bus, as appropriate, for all of the Energy delivered pursuant to the ISO Services Tariff. Conversely, when a Generator has negative net output for an interval and is self-supplying Station Power from the New York State Power System under Section 4.7.1.1 or 4.7.1.2, it will pay the Real-Time or Day-Ahead LBMP, as appropriate, for all of the Energy consumed, pursuant to the ISO Services Tariff.

4.7.5 The ISO will determine the extent to which each affected generator self-supplied its Station Power requirements or obtained Station Power from third-party providers (including corporate affiliates) during the Billing Period and will incorporate that determination in its accounting and billing. To the extent that Station Power deliveries from third parties, including corporate affiliates of a Generator's owner, involve an unbundled Transmission Service component, the Generator shall take Transmission Service under Part 5 of the ISO OATT unless the Generator has made other arrangements with the local Transmission Owner under the Transmission Owner's retail access tariff.

4.7.6 When a Generator self-supplies Station Power during any month according to Section 4.7.1.1, above, the Generator will not incur any charges for Transmission Service. When a Generator remotely self-supplies Station Power according to Section 4.7.1.2 above, the Generator shall, to the extent that Transmission Service is involved, pay for Transmission Service for the quantity of Energy that the Generator remotely self-supplies. Such Transmission Service shall be provided under Part 3 of the ISO OATT and shall be charged the hourly rate under Schedule 6.7 of the ISO OATT for Firm Point-to-Point Transmission Service, provided however, that the terms and charges under Schedules 6.1 through 6.3, 6.5, 6.6, 6.8 and 6.9 of the ISO OATT shall not apply to such service. The amount of Energy that a Generator transmits in conjunction with remote self-supply of Station Power will not be affected by any other sales, purchases, or transmission of Capacity or Energy by or for such Generator under any other provisions of the ISO OATT or ISO Services Tariff.

4.7.7 A Generator may remotely self-supply Station Power from an External Generator owned by the same entity that owns the Generator only if the External Generator has positive net output during the month and if the Generator has scheduled Imports into the NYCA from the External Generator during the month in an amount at least sufficient to offset fully its negative net output for the month.

5 CONTROL AREA SERVICES: RIGHTS AND OBLIGATIONS

5.1 Control Area Services

The ISO will provide Control Area Services in accordance with the standards and criteria of NERC and NPCC, the Reliability Rules of the NYSRC, and Good Utility Practice. The Control Area Services provided by the ISO include, but are not limited to, the following:

(a) Developing and implementing procedures to maintain the reliability of NYS Power System;

(b) Coordinating operations with other Control Area operators;

(c) Arranging for reserve sharing agreements with other ISOs and other Control Areas to enhance reliability during abnormal operating conditions;

(d) Coordinating the outage schedules for generating units and Installed Capacity Suppliers within the NYCA to maintain system reliability;

(e) Committing adequate generation resources to ensure the reliability of the NYS Power System;

(f) Taking command and control of the NYCA resources during Emergency conditions and coordinating operations with Transmission Owners;

(g) Maintaining and Operating a central control center and performing the functions of the NERC security control center for the NYCA under Emergency operating conditions;

(h) Defining the Installed Capacity requirements for LSEs, inclusive of individual customers taking services directly from the ISO, within the NYCA;

(i) Determining Locational Installed Capacity requirements for LSEs to ensure the reliable operation of the NYCA;

(j) Administering of an Installed Capacity market;

(k) Training the operating personnel of the ISO and Transmission Owner control rooms; and

(l) Administering the mandatory NERC reliability compliance process.

5.1.1 Customer Compliance with Reliability Standards; Penalties

5.1.1.1 Customer Compliance with Reliability Standards:

In accordance with applicable requirements in this Tariff and the ISO Procedures, all Customers shall conform to all applicable reliability criteria, policies, standards, rules, regulations and other requirements of NERC, NPCC, NYSRC, any applicable regional council, or their successors, the ISO's specific reliability requirements and ISO Procedures, and applicable operating guidelines and all applicable requirements of federal and state regulatory authorities. Failure to conform to these requirements may subject a Customer to direct assignment of penalties assessed against the ISO by FERC, NERC, NPCC or any other federal or state regulatory authority as a result of such Customer's failure to conform.

5.1.1.2 Direct Assignment of Penalty Costs:

The ISO's compliance with applicable reliability criteria, policies, standards, rules, regulations and other requirements is sometimes dependent on timely, accurate and adequate information and/or action on the part of a Customer. If the ISO is found to be non-compliant with respect to any applicable reliability criteria, policies, standards, rules, regulations and other requirements as a result of a Customer's actions or failure to act in violation of an obligation imposed by the ISO Tariffs, ISO Procedures, or ISO Related Agreements, the ISO may seek to directly assign to the Customer the cost of a penalty imposed on the ISO as a consequence of its non-compliance. If the Customer is found to be non-compliant with respect to any applicable reliability criteria, policies, standards, rules, regulations and other requirements as a result of the

ISO's actions or failure to act in violation of an obligation imposed by the ISO Tariffs, ISO Procedures, or ISO Related Agreements, the Customer may seek to directly assign to the ISO the cost of a penalty imposed on the Customer as a consequence of the ISO's non-compliance. Any direct assignment of penalty costs must first be approved by FERC, as provided in Schedule 6.11 of the OATT.

5.1.1.3 ISO's Recovery of Penalty Costs Through Schedule 11:

If direct assignment to a particular Customer is not possible or if the ISO is directly responsible for a violation because of its own action or inaction, the ISO may seek to recover such penalty costs in Schedule 6.11 Section 6.11.3 of the ISO OATT. Any inclusion of penalty costs in Schedule 6.11 must first be approved by FERC on a case-by-case basis, as provided in Schedule 6.11 of the ISO OATT. Prior to seeking FERC authorization for recovery of a penalty in Schedule 6.11 Section 6.11.3 of the ISO OATT, the ISO shall consult with the Management Committee and any appropriate subcommittee or working groups designated by the Management Committee, regarding the recovery and allocation of such penalty before filing at FERC. Any recommendation by the Management Committee regarding a proposed penalty recovery shall be reported by the ISO to FERC in any ISO filing seeking penalty recovery.

5.1.2 Incorporation of Certain Business Practice Standards

(a) Pursuant to Commission Order No. 676-K, the ISO incorporates by reference the following business practice standards developed by the North American Energy Standards Board's Wholesale Electric Quadrant:

(i) WEQ-000, Abbreviations, Acronyms, and Definition of Terms (Version 004, July 31, 2023);

(ii) WEQ-001, Open Access Same-Time Information Systems (OASIS) (WEQ Version 004, July 31, 2023), with Minor Correction MC24004

applied to standard WEQ-001-24.2.4 (August 9, 2024), except as provided in section 5.1.2(b) below;

(v) WEQ-004, Coordinate Interchange (WEQ Version 004, July 31, 2023), except as provided in section 5.1.2(b) below;

(vi) WEQ-005, Area Control Error (ACE) Equation Special Cases (WEQ Version 004, July 31, 2023);

(vii) WEQ-006, Manual Time Error Correction (WEQ Version 004, July 31, 2023);

(viii) WEQ-007 Inadvertent Interchange Payback (WEQ Version 004, July 31, 2023);

(ix) WEQ-008, Transmission Loading Relief (TLR) – Eastern Interconnection (WEQ Version 004, July 31, 2023);

(x) WEQ-011, Gas/Electric Coordination (WEQ Version 004, July 31, 2023);

(xi) WEQ-012, Public Key Infrastructure (PKI) (WEQ Version 004, July 31, 2023);

(xiii) WEQ-015, Measurement and Verification of Wholesale Electricity Demand Response (WEQ Version 004, July 31, 2023);

(xiv) WEQ-021, Measurement and Verification of Energy Efficiency Products (WEQ Version 004, July 31, 2023);

(xv) WEQ-022, Electric Industry Registry (EIR) (WEQ Version 004, July 31, 2023);

(xvi) WEQ-023, Modeling (WEQ Version 004, July 31, 2023), except as provided in section 5.1.2(b) below;

(xvii) WEQ-024, Cybersecurity (WEQ Version 004, July 31, 2023).

(b) The ISO is not required to comply with the following Standards:

(ii) WEQ-001 Open Access Same-Time Information Systems (OASIS), (WEQ Version 004, July 31, 2023) with Minor Correction MC24004 applied to standard WEQ-001-24.2.4 (August 9, 2024): Standards 001-2, 001-3, 001-4, 001-5, 001-6, 001-7, 001-8, 001-9, 001-10, 001-011, 001-012, 001-13.1.3 (c), 001-013.2, 001-014, 001-015, 001-016, 001-017, 001-020, 001-021, 001-022, 001-23, 001-24, 001-25, 001-26, 001-27, 001-28, 001-101 through 001-108, 001-Appendix A, and 001-Appendix B, pursuant to *New York Independent System Operator, Inc.*, 194 FERC ¶ 61,235 (March 27, 2026);

(iii) WEQ-002, Open Access Same-Time Information System (OASIS) Business Practice Standards and Communication Protocols (S&CP) (WEQ Version 004, July 31, 2023), pursuant to *New York Independent System Operator, Inc.*, 194 FERC ¶ 61,235 (March 27, 2026);

(iv) WEQ-003, Open Access Same-Time Information Systems (OASIS) Data Dictionary (WEQ Version 004, July 31, 2023), pursuant to *New York Independent System Operator, Inc.*, 194 FERC ¶ 61,235 (March 27, 2026);

(v) WEQ-004, Coordinate Interchange (WEQ Version 004, July 31, 2023): Standards 004-3, 004-18, 004-Appendix A and 004-Appendix C, pursuant to *New York Independent System Operator, Inc.*, 194 FERC ¶ 61,235 (March 27, 2026);

(xii) WEQ-013, Open Access Same-Time Information Systems (OASIS) Implementation Guide, (WEQ Version 004, July 31, 2023), pursuant to *New York Independent System Operator, Inc.*, 194 FERC ¶ 61,235 (March 27, 2026); and

(xvi) WEQ-023, Modeling, (WEQ Version 004, July 31, 2023), Standards WEQ-023-5; WEQ-023-6; and WEQ-023-A (Appendix A), pursuant to *New York Independent System Operator, Inc.*, 194 FERC ¶ 61,235 (March 27, 2026).

5.2 Independent System Operator Authority

The ISO will act as the Control Area operator, as defined by NERC, for the NYCA. The ISO will provide all Control Area Services in the NYCA. Control Area Services provided by the ISO will be in accordance with the terms of the ISO Services Tariff, the Reliability Rules, the ISO Related Agreements and Good Utility Practice. The ISO will act with other Control Area operators as required to modify External Transactions pursuant to this Tariff and to ensure the effective and reliable coordination with the interconnected Control Areas. In acting as the Control Area operator, the ISO will be responsible for maintaining the safety and the short-term reliability of the NYCA and for the implementation of reliability standards promulgated by NERC and NPCC and for the Reliability Rules promulgated by the NYSRC. To be included within NYCA, a Market Participant must meet the requirements of Section 5.6. Each Market Participant that (1) withdraws Energy to supply Load within the NYCA; or (2) provides Installed Capacity to an LSE serving Load within the NYCA, benefits from the Control Area Services provided by the ISO and from the reliability achieved as a result of ISO Control Area Services and therefore must take service as a Customer under the Tariff. To be included within NYCA, a Market Participant must meet the requirements of Section 5.6. A Market Participant that is not included within the NYCA may take service as a Customer under the Tariff, provided that it meets the requirements of Section 5.7.

5.2.1 Suspension of Virtual Transactions

The ISO may temporarily suspend Virtual Transactions if it determines that:

5.2.1.1 The financial exposure of customers engaged in Virtual Transactions cannot be determined with a reasonable degree of accuracy or to factors such as software or system failures;

5.2.1.2 A market aberration associated with Virtual Transactions substantially impairs the functioning of the ISO-administered markets; or

5.2.1.3 Virtual Transactions substantially impair the ability of the ISO to maintain the reliability of the electric system.

As soon as reasonably practicable, the ISO shall notify the Commission and Market Participants of the reason(s) for any suspension of Virtual Transactions, the action(s) necessary to restore Virtual Transactions, and the estimated time required to restore Virtual Transactions.

5.2.2 Suspension of the Ability of Generators to Increase Their Bids in Real-Time

The ISO may temporarily suspend the ability to submit Incremental Energy Bids in the real-time market that exceed the Incremental Energy Bids submitted in the Day-Ahead Market or the mitigated Day-Ahead Incremental Energy Bids where appropriate for the portions of Generators' Capacity that were scheduled in the Day-Ahead Market, if the ISO determines that:

5.2.2.1 a market aberration associated with Incremental Energy Bids submitted in the real-time market that exceed the Incremental Energy Bids submitted in the Day-Ahead Market for the portions of Generators' Capacity that were scheduled in the Day-Ahead Market substantially impairs the functioning of the ISO-administered markets; or

5.2.2.2 Permitting Incremental Energy Bids submitted in the real-time market to exceed the Incremental Energy Bids submitted in the Day-Ahead Market or the mitigated Day-Ahead Incremental Energy Bids where appropriate, for portions of Generators' Capacity that were scheduled in the Day-Ahead Market substantially impairs the ability of the ISO to maintain the reliability of the electric system.

As soon as reasonably practicable, the ISO shall notify the Commission and Market Participants of the reason(s) for any suspension of the ability for Incremental Energy Bids submitted in the real-time market to exceed the Incremental Energy Bids submitted in the Day-Ahead Market or the mitigated Day-Ahead Incremental Energy Bids where appropriate, for portions of Generators' Capacity that were scheduled in the Day-Ahead Market; the action(s) necessary to restore this feature to the ISO-Administered Markets; and the estimated time required to restore this feature to the ISO-Administered Markets.

5.3 Control Center Operation

The ISO will maintain and operate a control center in order to monitor the power flows on and across the NYCA, coordinate the flow of electricity within the NYCA, respond to Emergency situations, monitor power flows between the NYCA and neighboring Control Areas and maintain reliability.

5.3.1 Back-Up Operation

The ISO shall develop Back-Up Operation procedures that will carry out the intent and purposes of this ISO Services Tariff, to the extent practical, in circumstances under which the normal communications or computer systems of the ISO are not fully functional. Such procedures shall include testing requirements and training for the ISO staff, Transmission Owner staff, and Market Participants. If a communication or computer system malfunction results in the ISO's inability to operate the NYCA in accordance with ISO Procedures or under approved testing procedures, the ISO will direct the Transmission Owners to assume the responsibility to operate their respective systems, including facilities that a Transmission Owner has agreed to operate and maintain in accordance with an operation and maintenance agreement, in accordance with Good Utility Practice to facilitate the operation of the NYCA in a safe and reliable manner. The Transmission Owners will continue to operate their respective systems, including facilities that a Transmission Owner has agreed to operate and maintain in accordance with an operation and maintenance agreement, until such time that the ISO is ready to resume control. During Back-Up Operation, the Transmission Owner control centers will operate to maintain the Desired Net Interchange ("DNI") within each Transmission District. Generator Bid curves will be provided by the ISO to the individual Transmission Owners in order to permit dispatch by the Transmission Owners subject to the Transmission Owner code of conduct to the extent

applicable. Normal Day-Ahead Market and Real-Time Market operations may be halted, if required.

5.3.2 Market Participant and Customer Obligations

During Back-Up Operation, Customers and other Market Participants shall comply with any and all instructions and orders issued by the ISO or the Transmission Owners.

5.3.3 Billing and Settlement

In the event that Back-Up Operation is implemented, the billing and settlement procedures contained in Article 7 of this ISO Services Tariff shall apply only to the extent they can be implemented under the Back-Up Operation procedures. The ISO will follow specific billing and settlement procedures for use under the specific circumstances that required Back-Up Operation. The ISO shall gather necessary information, manually reconstruct the billing information as soon as practical, and submit invoices to Customers. The ISO shall be under no obligation to comply with the billing procedure time limits specified in Article 7. Neither the ISO nor the Transmission Owners shall be liable, under any circumstances, for any economic losses suffered by any Customer, Market Participant, or third party, resulting from the implementation by the ISO of Back-Up Operation, or from compliance with orders issued by the ISO or Transmission Owners that were necessary to operate the NYCA in a safe and reliable manner. Such orders may include, without limitation, instructions to generation facilities to increase or decrease output, and instructions to Load to reduce or interrupt service.

5.4 Operation Under Adverse Conditions

The ISO shall operate the NYS Power System during Adverse Conditions, including, but not limited to, thunder storms, hurricanes, tornadoes, solar magnetic flares and threat of terrorist activities, in accordance with the Reliability Rules, inclusive of Local Reliability Rules and related PSC orders. Consistent with such Reliability Rules, the ISO shall maintain reliability of the NYS Power System by directing the adjustment of the Generator output levels and controllable transmission devices in certain areas of the system to reduce power flows across transmission lines vulnerable to outages due to these Adverse Conditions, thereby reducing the likelihood of major power system disturbances.

The ISO shall have the sole authority to declare that Adverse Conditions are imminent or present and invoke the appropriate operating procedure(s) affecting the NYS Power System in response to those conditions. Activation of a procedure in compliance with a Local Reliability Rule shall involve a two (2) step process. The Transmission Owner directly involved with such Local Reliability Rule, such as Storm Watch, shall advise the ISO that Adverse Conditions are imminent or present and recommend to the ISO the activation of procedures in support of that Local Reliability Rule. Consistent with the Local Reliability Rule, the ISO shall declare the activation of the appropriate procedures.

The Transmission Owner and the ISO shall coordinate the implementation of the applicable procedures to the extent that Transmission Facilities under ISO Operational Control are impacted. Records pertaining to the activation of such procedures and the response in accordance with those procedures shall be maintained and made available upon request.

The Real-Time LBMPs shall be based on adjusted Generator levels set in response to activation of these procedures. Revenue shortfalls may occur if the redispatch of the system

Curtails Energy scheduled Day-Ahead and more expensive Energy is dispatched subsequent to the Day-Ahead Settlement. These revenue shortfalls shall be recovered by the ISO through the Rate Schedule 1 charge under the ISO OATT.

5.5 Major Emergency State

In the event of, or in order to prevent, a Major Emergency State, Customers shall comply with all ISO Procedures and Reliability Rules applicable to a Major Emergency State.

5.6 Requirements For Inclusion Within The New York Control Area

To be included within the NYCA a Supplier or a Load must meet the following requirements:

(a) Its facilities must be included within the NYCA.

(b) It must accept and comply with NYCA standards with respect to system design, equipment ratings, operating practices and maintenance practices as set forth in the ISO Procedures so that sufficient electrical equipment control capability, information and communication are available to the ISO for planning and operation of the NYCA.

(c) Its facilities must be able to respond to command and control instructions from the ISO.

(d) It must have compatible operational communication mechanisms, maintained at its expense, to interact with the ISO and for Internal requirements.

(e) It must ensure the continued compatibility of its local Energy management system, system monitoring and telecommunications systems to satisfy the technical requirements of interacting with the ISO as the ISO directs the operation of the NYCA.

5.7 Requirements For Entities Not Located Within The New York Control Area

In order for a Supplier or a Load that is not included within the NYCA to take services under the Tariff, it must be contained, in whole or in part, within a separate Control Area that meets all of the requirements for a Control Area defined by NERC, NPCC and any succeeding organizations. An entity that is contained in a Control Area other than the NYCA may take services under the ISO Services Tariff for the purpose of engaging in Control Area to Control Area Capacity and Energy Transactions with the ISO. In order for a Supplier or a Load not contained in the NYCA to take services under the ISO Services Tariff, an inter-Control Area agreement between the Control Area in which the entity is located and the ISO, that satisfies the reasonable requirements of both Control Area operators, must be in place. Energy Storage Resources, Intermittent Power Resources, and Limited Control Run of River Hydro Resources that are not electrically located within the NYCA are not eligible to participate in the ISO Installed Capacity market. Resources in External Control Areas that have an Energy Duration Limitation or are seeking to participate in the ISO's markets in an Aggregation are not eligible to participate in the ISO's Installed Capacity market.

5.8 Communication and Metering Requirements for Control Area Services

The ISO shall arrange for and maintain reliable communications and metering facilities between the ISO and the Transmission Owners in the NYCA and the Control Area operators of all neighboring interconnected Control Areas. Such facilities may consist of data circuits, voice lines, meters and other facilities deemed necessary by the ISO to maintain reliable communication links for the sole purpose of transmitting operations and reliability data and instructions. The ISO shall be responsible for the specification, installation and maintenance of the required facilities according to ISO Procedures. The costs incurred by the ISO to establish communications facilities between the ISO and a Security Coordinators of a neighboring Control Area shall be borne by the Control Area that requested the establishment of the communications facilities unless a different arrangement is agreed to by both Control Areas. The total cost of the communications facilities between the ISO and the Transmission Owners and the portion of the cost of inter-Control Area communication facilities assigned to the ISO shall be collected from all Customers in accordance with Rate Schedule 15.1 of the ISO Services Tariff. Transmission Owners with communications requirements which exceed those required by the ISO shall procure and maintain such additional facilities at their own expense.

Generators, Suppliers and Loads are required to exchange certain operating and reliability data with the ISO and the Transmission Owners' Control Centers in accordance with the ISO Agreement and the ISO/TO Agreement, applicable ISO operating and reliability requirements, and in conjunction with any requirements for interconnection with the Transmission Owner.

In addition, Suppliers wishing to submit Bids in the RTC for Energy or Regulation Service must make provision to receive command and control information from the ISO. Those Generators or Suppliers currently providing this capability via a Transmission Owner may

continue to do so. Those requiring installation of this capability must contract with the ISO or with the interconnected Transmission Owner and must comply with applicable ISO or Transmission Owner data and other technical requirements.

Suppliers with multiple units at a single location must maintain a consistent representation of the plant with the ISO with respect to the combination of all of the units at the single location, for purposes of bidding. If a single Bid is to be provided for a group of specific units at a plant and those units are bidding in the RTC, or providing Regulation Service, then the ISO shall model those units as a single group for purposes of dispatch, control and security modeling. The ISO will provide a single aggregate Base Point Signal and unit control error. If, however, the Supplier wishes to dispatch units individually, then it must configure both its bidding and data interfaces accordingly. Each Supplier must initially specify the configuration of the plant for purposes of bidding aggregation and must then maintain bidding and data interfaces consistent with that configuration. Similar modeling, control and bidding Constraints apply to an LSE that bids Load that is dispatchable by the ISO.

5.8.1 Collection and Communication of Energy Forecasting Data by Intermittent Power Resources that Depend on Wind or Solar Energy as Their Fuel

Pursuant to ISO Procedures, Intermittent Power Resources that depend on wind or solar energy as their fuel shall maintain in good working order equipment to collect data required for energy forecasting and shall provide the ISO, or its agent, with this data in the manner identified by the ISO, provided however this requirement shall not apply to (i) any stand-alone Intermittent Power Resource that depends on solar energy as its fuel with a nameplate capacity of 20 MW or fewer, or (ii) any Aggregation comprised entirely of Intermittent Power Resources that depend on solar energy as their fuel with a total nameplate capacity of 20 MW or fewer, or (iii) any

Intermittent Power Resource that depends on wind or solar energy as its fuel that participates in a DER Aggregation, or (iv) any Intermittent Power Resource in commercial operation as of January 1, 2002 with nameplate capacity of 12 MW or fewer.

An Intermittent Power Resource (except an Intermittent Power Resource participating in a DER Aggregation) that depends on wind as its fuel shall, in accordance with ISO Procedures, provide the ISO with wind speed and wind direction data for its site, and maximum available megawatt data.

An Intermittent Power Resource that depends on solar energy as its fuel and is not subject to one of the above exceptions shall, in accordance with ISO Procedures, provide the ISO with plane of array irradiance and back panel temperature data for its site, and maximum available megawatt data.

Each Intermittent Power Resource subject to this Section shall be responsible for the cost of installing and maintaining such equipment at its site, as well as the cost of installing and maintaining the software and hardware necessary to provide the required data described above, in accordance with ISO Procedures.

The ISO may impose financial sanctions for failure to provide the required data described above.

Upon a determination of failure to provide the required data, the ISO shall take the following actions. The ISO shall notify the Intermittent Power Resource by written notice of its determination of failure to provide the required data and that the ISO may impose financial sanctions if the failure is not corrected. The ISO shall offer a reasonable opportunity to correct the failure to provide the required data. If, following such reasonable opportunity to cure, such failure is not cured, the ISO may impose daily sanctions of the greater of $500 or $20/MW of

nameplate capacity until such failure is cured. The ISO shall offer the Intermittent Power Resource an opportunity to be heard by senior officers of the ISO prior to imposing sanctions.

5.9 Installed Capacity and Locational Export Capacity

5.9.1 Sections 5.10 through 5.17 of this Tariff, implementing the Installed Capacity market design, shall govern LSE Unforced Capacity Obligations, the qualification of Installed Capacity Suppliers, and the ISO's administration of Installed Capacity auctions.

5.9.2 Provisions applicable to Locational Export Capacity. Nothing in this Section alters the requirements in the ISO Tariffs or ISO Procedures generally applicable to Installed Capacity Suppliers and Generators.

5.9.2.2 Eligibility. In order to be eligible to export capacity from an Import Constrained Locality for an Obligation Procurement Period, the Market Participant for a Generator must:

5.9.2.2.1 Notify the ISO on or before the first business day of the month prior to the month of the export, specify the quantity of MW in ICAP, and the Control Area that will be entitled to the exported capacity, such notice in accordance with ISO Procedures; and

5.9.2.2.2 Provide all data and other information to the ISO required in accordance with Services Tariff Section 23.4.5.

5.9.2.3 During any month a Resource has Locational Export Capacity, the Market Participant for it shall Bid the Locational Export Capacity into the in-day market when the ISO issues a Supplemental Resource Evaluation request (an SRE), unless the entity has a bid pending in the Real-Time Market when the SRE request is made or is unable to bid in response to the SRE request due to an

outage as defined in the ISO Procedures, or due to other operational issues, or due to temperature related deratings.

5.10 NYCA Minimum Installed Capacity Requirements

5.10.1 NYCA Minimum Installed Capacity Requirements Applicable Prior to the 2027-2028 Capability Year

The NYCA Minimum Installed Capacity Requirement is derived from the NYCA Installed Reserve Margin, which is established each year by the NYSRC, and the NYCA Peak Load Forecast. The NYCA Minimum Installed Capacity Requirement for the Capability Year beginning each May 1 will be established by multiplying the NYCA Peak Load Forecast, which is determined by the ISO as described below in this section and Section 5.11 and in accordance with ISO Procedures, by the quantity of one plus the NYCA Installed Reserve Margin.

For the purpose of determining the Minimum UCAP Requirements for LSEs in the upcoming Capability Year, each Transmission Owner and each municipal electric utility will submit to the ISO, for its review pursuant to mutually agreed upon procedures which shall be described in the ISO Procedures, the weather-adjusted Load within its Transmission District during the non-NERC holiday weekday hour occurring in July or August in which actual Load in the NYCA was highest for the current Capability Year. (Municipal electric utilities may elect not to submit weather-adjusted data, in which case, weather adjustments shall be performed per ISO Procedures. The ISO shall use these data to determine the Adjusted Actual Load for this non-NERC holiday weekday hour for each Transmission District and municipal electric utility pursuant to ISO Procedures, which shall ensure that transmission losses and the effects of demand reduction programs and the other elements of Adjusted Actual Load are treated in a consistent manner and that all weather normalization procedures meet a minimum criterion described in the ISO Procedures. Each Load forecast for a Transmission District or municipal electric utility that is used to determine the coincident NYCA Peak Load Forecast for the

upcoming Capability Year shall be the product of that Transmission District or municipal electric utility's Adjusted Actual Load and one plus the regional Load growth factor for that Transmission District or municipal electric utility developed pursuant to Section 5.10 of this Tariff. After calculating each Transmission District or municipal electric utility Load forecast, if the ISO determines that an Adjusted Actual Load determined for a Transmission District or municipal electric utility does not reflect reasonable expectations of what Load might reasonably have been expected to occur in that Transmission District or area served by that municipal electric utility in that Capability Year, after taking into consideration the adjustments to account for weather normalization, transmission losses and demand response programs and other elements of Adjusted Actual Load that are described in the ISO Procedures, the ISO Procedures shall also authorize the ISO to substitute its own measures of Adjusted Actual Load for that Transmission District or area serviced by that municipal electric utility in this calculation, subject to the outcome of dispute resolution procedures if invoked. The ISO's measure of Adjusted Actual Load shall be binding unless otherwise determined as the result of dispute resolution procedures that may be invoked.

The ISO shall translate the NYCA Installed Reserve Margin, and thus the NYCA Minimum Installed Capacity Requirement, into a NYCA Minimum Unforced Capacity Requirement. For each subsequent Capability Period, the NYCA Minimum Unforced Capacity Requirement shall equal the product of the NYCA Minimum Installed Capacity Requirement and the ratio of (1) the total amount of Unforced Capacity that the specified Resources are qualified to provide during such Capability Period, as of the time the NYCA Minimum Unforced Capacity Requirement is determined as specified in ISO Procedures, to (2) the sum of the Installed

Capacity values used to determine the Unforced Capacities of such Resources for such Capability Period.

The foregoing calculation shall be determined using the Resources in the NYCA in the most recent final version of the ISO's annual Load & Capacity Data Report, with the addition of Resources commencing commercial operation since completion of that report and the deletion of Resources with scheduled or planned retirement dates before or during such Capability Period.

The NYCA Minimum Unforced Capacity Requirement represents a minimum level of Unforced Capacity that must be secured by LSEs in the NYCA for each Obligation Procurement Period. Under the provisions of this Services Tariff and the ISO Procedures, each LSE will be obligated to procure its LSE Unforced Capacity Obligation. The LSE Unforced Capacity Obligation will be determined for each Obligation Procurement Period by the ICAP Spot Market Auction, in accordance with ISO Procedures. Installed Capacity Suppliers will have the opportunity to supply amounts of Unforced Capacity to meet the LSE Unforced Capacity Obligation as established by the ICAP Spot Market Auction.

The ISO will calculate a NYCA Peak Load Forecast each year by applying regional Load growth factors to the prior calendar year's Adjusted Actual Load. Regional Load growth factors shall be proposed by the Transmission Owners and reviewed by the ISO pursuant to procedures agreed to by Market Participants and described in the ISO Procedures. Disputes concerning the development of regional Load growth factors shall be resolved through the Expedited Dispute Resolution Procedures set forth in Section 5.17 of this Tariff.

The ISO shall determine the amount of Unforced Capacity that must be sited within the NYCA, and within each Locality, and the amount of Unforced Capacity that may be procured

from areas External to the NYCA, in a manner consistent with the Reliability Rules. New transmission projects to which the NYISO has granted UDRs will not affect the determination by the ISO of the amount of Unforced Capacity that must be located within the NYCA or within each Locality of the NYCA.

5.10.2 NYCA Minimum Installed Capacity Requirements Applicable Starting with the 2027-2028 Capability Year

The NYCA Minimum Installed Capacity Requirements are derived from the NYCA Installed Reserve Margin and the NYCA Winter Installed Reserve Margin for the Summer Capability Period and Winter Capability Period, respectively. The NYCA Minimum Installed Capacity Requirement for the Summer Capability Period of the upcoming Capability Year will be established by multiplying the NYCA Peak Load Forecast for that Summer Capability Period, which is determined by the ISO as described below in this section and Section 5.11 and in accordance with the ISO Procedures, by the quantity of one plus the NYCA Installed Reserve Margin. The NYCA Minimum Installed Capacity Requirement for the Winter Capability Period of the upcoming Capability Year will be established by multiplying the NYCA Peak Load Forecast for the Winter Capability Period, which is determined by the ISO as described below in this section and Section 5.11 and in accordance with the ISO Procedures, by the quantity of one plus the NYCA Winter Installed Reserve Margin.

For the purpose of determining the Minimum UCAP Requirements for LSEs in the upcoming Summer Capability Period, each Transmission Owner and each municipal electric utility will submit to the ISO, for its review pursuant to mutually agreed upon procedures which shall be described in the ISO Procedures, the weather-adjusted Load within its Transmission District during the non-NERC holiday weekday hour occurring in July or August in which actual

Load in the NYCA was highest for the Summer Capability Period of the current Capability Year. Municipal electric utilities may elect not to submit weather-adjusted data, in which case, weather adjustments shall be performed in accordance with the ISO Procedures.

For the purpose of determining the Minimum UCAP Requirements for LSEs in the upcoming Winter Capability Period, each Transmission Owner and each municipal electric utility will submit to the ISO, for its review pursuant to mutually agreed upon procedures which shall be described in the ISO Procedures, the weather-adjusted Load within its Transmission District during the non-NERC holiday weekday hour occurring in December, January or February in which actual Load in the NYCA was highest for the most recent Winter Capability Period. Municipal electric utilities may elect not to submit weather-adjusted data, in which case, weather adjustments shall be performed in accordance with ISO Procedures.

The ISO shall use this data to determine the Adjusted Actual Load for the non-NERC holiday weekday hour for each Transmission District and municipal electric utility in each Capability Period pursuant to the ISO Procedures, which shall ensure that transmission losses and the effects of demand reduction programs and the other elements of Adjusted Actual Load are treated in a consistent manner and that all weather normalization procedures meet a minimum criterion described in the ISO Procedures. Each Load forecast for a Transmission District or municipal electric utility that is used to determine the coincident NYCA Peak Load Forecast for each upcoming Capability Period shall be the product of that Transmission District or municipal electric utility's Adjusted Actual Load for the given Capability Period and one plus the regional Load growth factor for that Transmission District or municipal electric utility developed pursuant to Section 5.10 of this Tariff. After calculating each Transmission District or municipal electric

utility Load forecast, if the ISO determines that an Adjusted Actual Load determined for a Transmission District or municipal electric utility does not reflect reasonable expectations of what Load might reasonably have been expected to occur in that Transmission District or area served by that municipal electric utility in the given Capability Period, after taking into consideration the adjustments to account for weather normalization, transmission losses, demand response programs, and other elements of Adjusted Actual Load that are described in the ISO Procedures, the ISO Procedures shall also authorize the ISO to substitute its own measures of Adjusted Actual Load for that Transmission District or area serviced by that municipal electric utility in this calculation, subject to the outcome of the resolution of a dispute through the Expedited Dispute Resolution Procedures set forth in the NYISO Services Tariff Section 5.17. The ISO's measure of Adjusted Actual Load shall be binding unless otherwise determined as the result of the Expedited Dispute Resolution Procedures specified in the NYISO Services Tariff Section 5.17.

The ISO shall translate the NYCA Minimum Installed Capacity Requirements for each Capability Period into NYCA Minimum Unforced Capacity Requirements for each Capability Period. For each Capability Period, the NYCA Minimum Unforced Capacity Requirements shall equal the product of the respective Capability Period's NYCA Minimum Installed Capacity Requirement and the ratio of (1) the total amount of Unforced Capacity that the specified Resources are qualified to provide during such Capability Period as of the time the NYCA Minimum Unforced Capacity Requirement is determined as specified in the ISO Procedures to (2) the sum of the Installed Capacity values used to determine the Unforced Capacities of such Resources for such Capability Period.

The foregoing calculations shall be determined using the Resources in the NYCA in the most recent final version of the ISO's annual Load & Capacity Data Report, with the addition of Resources commencing commercial operation since completion of that report and the deletion of Resources with scheduled or planned retirement dates before or during such Capability Period.

The NYCA Minimum Unforced Capacity Requirements represent minimum levels of Unforced Capacity that must be secured by LSEs in the NYCA for each Obligation Procurement Period in the respective Capability Period. Under the provisions of this Services Tariff and the ISO Procedures, each LSE shall be obligated to procure its LSE Unforced Capacity Obligation. The LSE Unforced Capacity Obligation will be determined for each Obligation Procurement Period by the ICAP Spot Market Auction, in accordance with the ISO Procedures. Installed Capacity Suppliers shall have the opportunity to supply amounts of Unforced Capacity to meet the LSE Unforced Capacity Obligation as established by the ICAP Spot Market Auction.

The ISO will calculate a NYCA Peak Load Forecast for each Capability Period by applying regional Load growth factors to the prior Capability Period's Adjusted Actual Load for the applicable Capability Period. Regional Load growth factors shall be proposed by the Transmission Owners and reviewed by the ISO pursuant to procedures agreed to by Market Participants and described in the ISO Procedures. Disputes concerning the development of regional Load growth factors shall be resolved through the Expedited Dispute Resolution Procedures set forth in Section 5.17 of this Services Tariff.

The ISO shall determine the amount of Unforced Capacity that must be sited within the NYCA, and within each Locality, and the amount of Unforced Capacity that may be procured from areas External to the NYCA, in a manner consistent with the Reliability Rules. New

transmission projects to which the NYISO has granted UDRs will not affect the determination by the ISO of the amount of Unforced Capacity that must be located within the NYCA or within each Locality of the NYCA.

5.11 Requirements Applicable to LSEs

5.11.1 Allocation of the NYCA Minimum Unforced Capacity Requirement

Each Transmission Owner must submit aggregate Adjusted Actual Load data, coincident with the hour of the NYCA Peak Load Forecast, for all customers served by each LSE active within its Transmission District. The aggregate Adjusted Actual Load data may be derived from direct meters or Load profiles of the customers served. Each Transmission Owner shall be required to submit such aggregate Adjusted Actual Load data and peak Load forecasts for each LSE active within its Transmission District, in accordance with the ISO Procedures, that the ISO shall use to allocate the NYCA Minimum Unforced Capacity Requirement among all LSEs serving Load in the NYCA. Each municipal electric utility may choose to submit its peak Load forecast based on the Transmission District's peak Load forecast provided by a Transmission Owner or to provide its own. The ISO shall consider, in accordance with ISO Procedures, the effects of Demand Reductions by DER participating in the Installed Capacity Market to determine the Adjusted Actual Load to prevent double-counting the Demand Reduction in the LSE Unforced Capacity Obligation. Any disputes arising out of the submittals required in this paragraph shall be resolved through the Expedited Dispute Resolution Procedures set forth in Section 5.17 of this Tariff.

All aggregate Adjusted Actual Load data submitted by a Transmission Owner must be accompanied by documentation indicating that each affected LSE has been provided the data regarding the assignment of customers to the affected LSE. Any disputes between LSEs and Transmission Owners regarding such data or assignments shall be resolved through the Expedited Dispute Resolution Procedures set forth in Section 5.17 of this Tariff, or the Transmission Owner's retail access procedures, as applicable.

Prior to the 2027-2028 Capability Year, subject to Section 5.11.7 of this ISO Services Tariff, the ISO shall allocate the NYCA Minimum Unforced Capacity Requirement among all LSEs serving Load in the NYCA prior to the beginning of each Capability Year. It shall then adjust the NYCA Minimum Unforced Capacity Requirement and reallocate it among LSEs before each Winter Capability Period as necessary to reflect changes in the factors used to translate ICAP requirements into Unforced Capacity requirements. Each LSE's share of the NYCA Minimum Unforced Capacity Requirement will equal the product of: (i) the NYCA Minimum Installed Capacity Requirement as translated into a NYCA Minimum Unforced Capacity Requirement; and (ii) the ratio of the sum of the Load forecasts coincident with the NYCA Peak Load Forecast for that LSE's customers in each Transmission District to the NYCA Peak Load Forecast.

Starting with the 2027-2028 Capability Year, subject to Section 5.11.7 of this ISO Services Tariff, the ISO shall allocate the applicable NYCA Minimum Unforced Capacity Requirement among all LSEs serving Load in the NYCA prior to the beginning of each Capability Period. Each LSE's share of the NYCA Minimum Unforced Capacity Requirement will equal the product of (i) the NYCA Minimum Installed Capacity Requirement as translated into a NYCA Minimum Unforced Capacity Requirement and (ii) the ratio of the sum of the Load forecasts coincident with the NYCA Peak Load Forecast for that LSE's customers in each Transmission District to the NYCA Peak Load Forecast for the applicable Capability Period.

Each LSE Unforced Capacity Obligation will equal the product of (i) the ratio of that LSE's share of the NYCA Minimum Unforced Capacity Requirement to the total NYCA Minimum Unforced Capacity Requirement and (ii) the total of all of the LSE Unforced Capacity Obligations for the NYCA established by the ICAP Spot Market Auction. The LSE Unforced

Capacity Obligation will be determined in each Obligation Procurement Period by the ICAP Spot Market Auction, in accordance with the ISO Procedures. Each LSE will be responsible for acquiring sufficient Unforced Capacity to satisfy its LSE Unforced Capacity Obligations. LSEs with Load in more than one Locality will have an LSE Unforced Capacity Obligation for each Locality.

Prior to the beginning of each Capability Period, Transmission Owners shall submit the required Load-shifting information to the ISO and to each LSE affected by the Load-shifting, in accordance with the ISO Procedures. In the event that there is a pending dispute regarding a Transmission Owner's forecast, the ISO shall nevertheless establish each LSE's portion of the NYCA Minimum Unforced Capacity Requirement applicable at the beginning of each Capability Period in accordance with the schedule established in the ISO Procedures, subject to possible adjustments that may be required as a result of resolution of the dispute through the Expedited Dispute Resolution Procedures set forth in Section 5.17 of this Tariff.

Each month, as Transmission Owners report customers gained and lost by LSEs through Load-shifting, the ISO will adjust each LSE's portion of the NYCA Minimum Unforced Capacity Requirement such that (i) the total Transmission District Installed Capacity requirement remains constant and (ii) an individual LSE's allocated portion reflects the gains and losses. If an LSE loses a customer as a result of that customer leaving the Transmission District, the Load-losing LSE shall be relieved of its obligation to procure Unforced Capacity to cover the Load associated with the departing customer as of the date that the customer's departure is accepted by the ISO and shall be free to sell any excess Unforced Capacity. In addition, when a customer leaves the Transmission District, the ISO will adjust each LSE's portion of the NYCA

Minimum Unforced Capacity Requirement so that the total Transmission District's share of the NYCA Minimum Unforced Capacity Requirement remains constant.

5.11.2 LSE Obligations

Each LSE must procure Unforced Capacity in an amount equal to its LSE Unforced Capacity Obligation from any Installed Capacity Supplier through Bilateral Transactions with purchases in ISO-administered Installed Capacity auctions, by self-supply from qualified sources, or by a combination of these methods. Each LSE must certify the amount of Unforced Capacity it has or has obtained prior to the beginning of each Obligation Procurement Period by submitting completed Installed Capacity certification forms to the ISO by the date specified in the ISO Procedures. The Installed Capacity certification forms submitted by the LSEs shall be in the format and include all the information prescribed by the ISO Procedures.

All LSEs shall participate in the ICAP Spot Market Auction pursuant to Section 5.14.1 of this Tariff.

5.11.3 Load-Shifting Adjustments

The ISO shall account for Load-shifting among LSEs each month using the best available information provided to it and the affected LSEs by the individual Transmission Owners**.** The ISO shall, upon notice of Load-shifting by a Transmission Owner and verification by the relevant Load-losing LSE, increase the Load-gaining LSE's LSE Unforced Capacity Obligation, as applicable, and decrease the Load-losing LSE's LSE Unforced Capacity Obligation, as applicable, to reflect the Load-shifting.

The Load-gaining LSE shall pay the Load-losing LSE an amount, pro-rated on a daily basis, based on the Market-Clearing Price of Unforced Capacity determined in the most recent previous applicable ICAP Spot Market Auction until the first day of the month after the nearest

following Monthly Installed Capacity Auction is held. The amount paid by a Load-gaining LSE shall reflect any portion of the Load-losing LSE's LSE Unforced Capacity Obligation that is attributable to the shifting Load for the applicable Obligation Procurement Period, in accordance with the ISO Procedures. In addition, the amount paid by a Load-gaining LSE shall be reduced by the Load-losing LSE's share of any rebate associated with the lost Load paid pursuant to Section 5.15 of this Tariff.

Each Transmission Owner shall report to the ISO and to each LSE serving Load in its Transmission District the updated, aggregated LSE Loads with documentation in accordance with and by the date set forth in the ISO Procedures. The ISO shall reallocate a portion of the NYCA Minimum Unforced Capacity Requirement and the Locational Minimum Unforced Capacity Requirement, as applicable, to each LSE for the following Obligation Procurement Period, which shall reflect all documented Load-shifts as of the end of the current Obligation Procurement Period. Any disputes among Market Participants concerning Load-shifting shall be resolved through the Expedited Dispute Resolution Procedures set forth in Section 5.17 of this Tariff, or the Transmission Owner's retail access procedures, as applicable. In the event of a pending dispute concerning a Load-shift, the ISO shall make its Obligation Procurement Period Installed Capacity adjustments as if the Load-shift reported by the Transmission Owners had occurred, or if the dispute pertains to the timing of a Load-shift, as if the Load-shift occurred on the effective date reported by the Transmission Owner, but will retroactively modify these allocations, as necessary, based on determinations made pursuant to the Expedited Dispute Resolution Procedures set forth in Section 5.17 of this Tariff, or the Transmission Owner's retail access procedures, as applicable.

5.11.4 LSE Locational Minimum Installed Capacity Requirements

Prior to the 2027-2028 Capability Year, subject to Section 5.11.7 of this ISO Services Tariff, the ISO will determine the Locational Minimum Installed Capacity Requirements, stated as a percentage of the Locality's forecasted Capability Year peak Load and expressed in Unforced Capacity terms, that shall be uniformly applicable to each LSE serving Load within a Locality. Starting with the 2027-2028 Capability Year, subject to Section 5.11.7 of this ISO Services Tariff, the ISO will determine the Locational Minimum Installed Capacity Requirements, stated as a percentage of the Locality's forecasted peak Load for the applicable Capability Period and expressed in Unforced Capacity terms, that shall be uniformly applicable to each LSE serving Load within a Locality for the applicable Capability Period. In establishing Locational Minimum Installed Capacity Requirements, the ISO will take into account all relevant considerations, including the total NYCA Minimum Installed Capacity Requirement, the NYS Power System transmission Interface Transfer Capability, the election by the holder of rights to UDRs that can provide Capacity from an External Control Area with a capability year start date that is different than the corresponding ISO Capability Year start date ("dissimilar capability year"), the Reliability Rules and any other FERC-approved Locational Minimum Installed Capacity Requirements.

The ISO shall compute the Locational Minimum Installed Capacity Requirements in accordance with ISO Procedures:

(a) to minimize the total cost of capacity at the prescribed level of excess. For purposes of this computation, the ISO shall use the prescribed level of excess (as such term is defined in Section 5.14.1.2.2 of this Tariff,) and shall take into account the cost curves established with the results of net Energy and Ancillary

Services revenue offset (as such term is defined in Section 5.14.1.2.2 of this Tariff,) that are (i) if for the first Capability Year covered by the applicable periodic review (as described in Section 5.14.1.2.2 of this Tariff,) the values utilized by the ISO in calculating the reference points for each ICAP Demand Curve as proposed by the ISO to be applicable for such first year in the ISO's filing referenced in Section 5.14.1.2.2.4.11 of this Tariff; and (ii) if for any subsequent Capability Year covered by such periodic review, the values utilized by the ISO in calculating the reference points for each ICAP Demand Curve for the respective Capability Year.

(b) to maintain the loss of load expectation of no more than 0.1 days per year; and

(c) so that the transmission security limits determined by the ISO in accordance with this paragraph and ISO Procedures, are respected. The ISO will determine these limits using inputs consistent with the NYSRC Installed Reserve Margin base case for the Capability Year to which the Locational Minimum Installed Capacity Requirements will apply except as provided in Section 5.11.7 of this ISO Services Tariff. The ISO will compute such limits by determining the bulk power system transmission capability into the Locality, the MW of generation within the Locality accounting for capacity unavailability, the minimum MW of available capacity required for each Locality based on forecasted Load, and using the N-1-1 system planning criteria (*i.e.*, a sequence of a primary contingency event followed by a secondary contingency event) to analyze thermal limits affecting the Locality. The ISO will post on its web site a report of its determination.

In computing the Locational Minimum Installed Capacity Requirements, the ISO shall utilize results from probabilistic modeling of reliability simulations, recognizing system constraints.

The Installed Capacity Supplier holding rights to UDRs from an External Control Area with a dissimilar capability year shall have one opportunity for a Capability Year in which the Scheduled Line will first be used to offer Capacity associated with the UDRs to elect that the ISO determine Locational Minimum Installed Capacity Requirements without a quantity of MW from the UDRs for the first month in the Capability Year and with the same quantity of MW as Unforced Capacity for the remaining months as elected by the UDR rights holder, in each case (a) consistent with and as demonstrated by a contractual arrangement to utilize the UDRs to import the quantity of MW of Capacity into a Locality and (b) in accordance with ISO Procedures (a "capability year adjustment election"). If there is more than one Installed Capacity Supplier holding rights to UDRs concurrently, an Installed Capacity Supplier's election pursuant to the preceding sentence (x) shall be binding on the entity to which the NYISO granted the UDRs up to the quantity of MW to which the Installed Capacity Supplier holds rights, and a subsequent assignment of these UDRs to another rights holder will not create the option for another one-time election by the new UDR rights holder, and (y) shall not affect the right another Installed Capacity Supplier may have to make an election. The right to make an election shall remain unless and until an election has been made by one or more holders of rights to the total quantity of MW corresponding to the UDRs. Absent this one-time election, the UDRs shall be modeled consistently for all months in each Capability Year as elected by the UDR rights holder in its notification to the ISO in accordance with ISO Procedures. Prior to the 2027-2028 Capability Year, upon such an election, the ISO shall determine the Locational Minimum

Unforced Capacity Requirement (i) for the first month of the Capability Year without the quantity of MW of Capacity associated with the UDRs and (ii) for the remaining eleven months as Unforced Capacity. Starting with the 2027-2028 Capability Year, upon such election, the ISO shall determine the Locational Minimum Unforced Capacity Requirement (i) for the first month of the Summer Capability Period without the quantity of MW of Capacity associated with the UDRs and (ii) for the remaining five months as Unforced Capacity. After the Installed Capacity Supplier has made its one-time election for a quantity of MW, the quantity of MW associated with the UDRs held by the Installed Capacity Supplier shall be modeled consistently for all months in any future Capability Period.

5.11.5 The Locational Minimum Unforced Capacity Requirement

The Locational Minimum Unforced Capacity Requirement represents a minimum level of Unforced Capacity that must be secured by LSEs in each Locality in which it has Load for each Obligation Procurement Period. Subject to Section 5.11.7 of this ISO Services Tariff, the Locational Minimum Unforced Capacity Requirement for each Locality shall equal the product of the Locational Minimum Installed Capacity Requirement for a given Locality ((A) with or without the UDRs if there is a capability year adjustment election by a rights holder and (B) without the Locality Exchange MW) and the ratio of (1) the total amount of Unforced Capacity that the specified Resources are qualified to provide (with or without the UDRs associated with dissimilar capability periods, as so elected by the rights holder) during each month in the Capability Period, as of the time the Locational Minimum Unforced Capacity Requirement is determined as specified in ISO Procedures, to (2) the sum of the Installed Capacity values used to determine the Unforced Capacities of such Resources for such Capability Period (with or without the DMNCs associated with the UDRs, as so elected by the rights holder).

The foregoing calculation shall be determined using the Resources in the given Locality in the most recent final version of the ISO's annual Load and Capacity Data Report, with the addition of Resources commencing commercial operation since completion of that report and the deletion of Resources with scheduled or planned retirement dates before or during such Capability Period. The ISO will apply the Locality Exchange Factor for the applicable External Control Area to the MW of Locational Export Capacity that are the lesser of (i) the lesser of the Generator's CRIS and its most recent DMNC, and (ii) the MW pursuant to the notice provided pursuant to Section 5.9.2.2.1 of this Services Tariff.

Under the provisions of this Services Tariff and the ISO Procedures, each LSE will be obligated to procure its LSE Unforced Capacity Obligation. The LSE Unforced Capacity Obligation will be determined for each Obligation Procurement Period by the ICAP Spot Market Auction, in accordance with the ISO Procedures.

Installed Capacity Suppliers will have the opportunity to supply amounts of Unforced Capacity to meet the LSE Unforced Capacity Obligation as established by the ICAP Spot Market Auction.

To be counted towards the locational component of the LSE Unforced Capacity Obligation, Unforced Capacity owned by the holder of UDRs or contractually combined with UDRs must be deliverable to the NYCA interface with the UDR transmission facility pursuant to NYISO requirements and consistent with the election of the holder of the rights to the UDRs set forth in this Section.

The ISO shall have the right to audit all executed Installed Capacity contracts and related documentation of arrangements by an LSE to use its own generation to meet its Locational Minimum Installed Capacity Requirement for an upcoming Obligation Procurement Period.

5.11.6 Determination of Locality Exchange Factor:

No later than January 31 each year, the ISO shall determine the Locality Exchange Factor for each Import Constrained Locality relative to each neighboring Control Area.

The ISO shall make each such determination by performing a power flow based analysis according to applicable transmission system planning practices for the determination of interface transfer limits used for the resource adequacy topology. Base case data from the most recent Reliability Planning Process will be incorporated. The Locality Exchange Factor is the ratio of the shift factor on the applicable NYCA interface of a transfer from the Import Constrained Locality to the respective neighboring Control Area, to the shift factor of a transfer from Rest of State to the Import Constrained Locality, calculated in accordance with ISO Procedures. Only the AC circuits comprising the respective neighboring Control Area's interface with the NYCA will participate in the shift. The ISO shall post its Locality Exchange Factors on its website prior to the opening of the Summer Capability Period Auction, and notify the New York State Reliability Council.

5.11.7 ICAP Market Parameters for Triggering Resources

The ISO shall identify whether the upcoming Capability Year includes a Triggering Resource prior to determining the Locational Minimum Installed Capacity Requirements for such Capability Year.

If more than one potential new Installed Capacity Supplier would otherwise qualify as a Triggering Resource for a given Capability Year, one of such potential new Installed Capacity Supplier shall be designated as the Triggering Resource for such Capability Year based on consideration of each such potential new Installed Capacity Supplier's respective impact on the transfer capability into a Locality, their respective potential impact on ICAP market parameters,

and their respective potential timing to commence participation in the ICAP market. The ISO shall review with Market Participants its proposed designation and obtain Operating Committee approval of the potential new Installed Capacity Supplier designated as the Triggering Resource for such Capability Year.

If the ISO has identified that a Triggering Resource exists for the upcoming Capability Year, the ISO shall determine two sets of ICAP market parameters for such Capability Year. For each set of ICAP market parameters, the ISO shall determine the NYCA Minimum Unforced Capacity Requirement pursuant to Section 5.10 of this ISO Services Tariff, Locational Minimum Installed Capacity Requirements pursuant to Section 5.11.4 of this ISO Services Tariff, LSE Unforced Capacity Requirements pursuant to Section 5.11 of this ISO Services Tariff, Capacity Accreditation Factors pursuant to Section 5.12.14.3 of this ISO Services Tariff, the amount of Unforced Capacity each Resource is qualified to supply in the NYCA pursuant to Section 5.12.6 of this ISO Services Tariff, and Unforced Capacity demand curves pursuant to Section 5.14.1.2 of this ISO Services Tariff. The ISO shall determine the respective ICAP market parameters for each set consistent with the timing requirements set forth in this ISO Services Tariff and ISO Procedures.

The starting database for each set of ICAP market parameters and procedures for determining the applicable set of ICAP market parameters is further described herein. Section 5.11.7.1 of this ISO Services Tariff addresses circumstances when a Triggering Resource is included as supplying ICAP in the final base case model approved by the NYSRC for determining the NYCA Installed Reserve Margin applicable to the Capability Year during which such Triggering Resource first seeks to commence participation in the ICAP market. Section 5.11.7.2 of this ISO Services Tariff addresses circumstances when a Triggering Resource has not

been included as supplying ICAP in the final base case model approved by the NYSRC for determining the NYCA Installed Reserve Margin applicable to the Capability Year during which such Triggering Resource first seeks to commence participation in the ICAP market.

5.11.7.1 Triggering Resources Included in the IRM Study Final Base Case

For a Capability Year with a Triggering Resource that has been included and is assumed to supply ICAP in the final base case model approved by the NYSRC for determining the NYCA Installed Reserve Margin applicable to such Capability Year, the following procedures shall apply for the two sets of ICAP market parameters that the ISO is required to develop for such Capability Year.

One set of ICAP market parameters shall be determined using the case resulting from the NYCA Installed Reserve Margin approved by the NYSRC for such Capability Year as the starting database (for purposes of this Section 5.11.7.1 hereinafter referred to as "Case 1A"). Except for the determination of import limits for External Installed Capacity and the Peak Load Window, the starting database for determining the second set of ICAP market parameters shall be Case 1A adjusted to remove the Triggering Resource while not exceeding the loss of load expectation associated with Case 1A and maintaining the NYCA Installed Reserve Margin approved by the NYSRC (for purposes of this Section 5.11.7.1 hereinafter referred to as "Case 1B"). The import limits for External Installed Capacity established pursuant to Section 5.12.2.2 of this ISO Services Tariff and the Peak Load Window established pursuant to Section 5.12.14.3 of this ISO Services Tariff shall be the same for each set of ICAP market parameters and shall be determined using Case 1A as the starting database.

The ISO shall identify the ICAP market parameters that will apply beginning with the May Obligation Procurement Period in a notice prior to the start of the Capability Period Auction

for the Summer Capability Period encompassed by such Capability Year. If, in accordance with Section 5.11.7.3 of this ISO Services Tariff and ISO Procedures, the Triggering Resource provides the required notice of intent to commence participation in the ICAP market for the May Obligation Procurement Period of such Capability Year, the ISO shall, within five (5) business days after receipt of the Triggering Resource's required notice of intent to commence ICAP market participation, provide notice that ICAP market parameters determined using Case 1A shall apply for the entire Capability Year.

If the Triggering Resource does not provide such required notice of intent to commence ICAP market participation for the May Obligation Procurement Period of such Capability Year, the ISO shall provide notice that ICAP market parameters determined using Case 1B shall be implemented starting with the May Obligation Procurement Period. ICAP market parameters determined using Case 1B shall remain in effect until the Obligation Procurement Period during such Capability Year for which the Triggering Resource, in accordance with Section 5.11.7.3 of this ISO Services Tariff and ISO Procedures, provides the required notice of intent to commence ICAP market participation; provided, however, if the Triggering Resource does not provide such required notice of intent to commence ICAP market participation for an Obligation Procurement Period prior to the November Obligation Procurement Period of such Capability Year, the ISO shall provide notice prior to the start of the Capability Period Auction for the Winter Capability Period encompassed by such Capability Year confirming that ICAP market parameters determined using Case 1B shall remain in effect for the balance of the Capability Year.

If, in accordance with Section 5.11.7.3 of this ISO Services Tariff and ISO Procedures, the Triggering Resource does not provide the required notice of intent to commence ICAP market participation for the May Obligation Procurement Period of such Capability Year but

provides such required notice of its intent to commence ICAP market participation for an Obligation Procurement Period prior to the November Obligation Procurement Period of such Capability Year, the ISO shall provide notice within five (5) business days after receipt of the Triggering Resource's notice of intent to commence ICAP market participation to indicate that the ISO will implement ICAP market parameters determined using Case 1A beginning with the same Obligation Procurement Period designated by the Triggering Resource's notice of intent to commence ICAP market participation, except for the 2026-2027 Winter Capability Period as described below. Except for the 2026-2027 Winter Capability Period as described below, ICAP market parameters determined using Case 1A shall be implemented beginning with the applicable Obligation Procurement Period, as determined in accordance with the immediately preceding sentence, and remain in effect for the balance of the Capability Year. For the 2026-2027 Capability Year, the ISO will implement ICAP market parameters determined using Case 1A beginning with the same Obligation Procurement Period designated by the Triggering Resource's notice of intent to commence ICAP market participation and such ICAP market parameters shall remain in effect for the balance of the Capability Year, except for the Locational Minimum Installed Capacity Requirement applicable for Load Zone J (and resulting LSE Unforced Capacity Requirements) during the 2026-2027 Winter Capability Period. For the 2026-2027 Winter Capability Period, the Locational Minimum Installed Capacity Requirement applicable for Load Zone J shall be as follows: (1) the value determined using Case 1A shall apply for each of the November 2026, March 2027, and April 2027 Obligation Procurement Periods; and (2) the value determined using Case 1B shall apply for each of the December 2026, January 2027, and February 2027 Obligation Procurement Periods. In addition, the ICAP Demand Curves applicable for all months covered by the 2026-2027 Winter Capability Period

shall be as set forth in Section 5.14.1.2.1 of this ISO Services Tariff. Such ICAP Demand Curves shall be translated into Unforced Capacity terms in accordance with ISO Procedures using the applicable ICAP market parameters determined using Case 1A.

5.11.7.2 Triggering Resources Not Included in the IRM Study Final Base Case

For a Capability Year with a Triggering Resource that has not been included and is not assumed to supply ICAP in the final base case model approved by the NYSRC for determining the NYCA Installed Reserve Margin applicable to such Capability Year, the following procedures shall apply for the two sets of ICAP market parameters that the ISO is required to develop for such Capability Year.

One set of ICAP market parameters shall be determined using the case resulting from the NYCA Installed Reserve Margin approved by the NYSRC for such Capability Year as the starting database (for purposes of this Section 5.11.7.2 hereinafter referred to as "Case 2A"). Except for the determination of import limits for External Installed Capacity and the Peak Load Window, the starting database for determining the second set of ICAP market parameters shall be Case 2A adjusted to include the Triggering Resource as supplying ICAP while not exceeding the loss of load expectation associated with Case 2A and maintaining the NYCA Installed Reserve Margin approved by the NYSRC (for purposes of this Section 5.11.7.2 hereinafter referred to as "Case 2B"). The import limits for External Installed Capacity established pursuant to Section 5.12.2.2 of this ISO Services Tariff and the Peak Load Window established pursuant to Section 5.12.14.3 of this ISO Services Tariff shall be the same for each set of ICAP market parameters and shall be determined using Case 2A as the starting database.

The ISO shall identify the ICAP market parameters that will apply beginning with the May Obligation Procurement Period in a notice prior to the start of the Capability Period Auction

for the Summer Capability Period encompassed by such Capability Year. If, in accordance with Section 5.11.7.3 of this ISO Services Tariff and ISO Procedures, the Triggering Resource provides the required notice of intent to commence participation in the ICAP market for the May Obligation Procurement Period of such Capability Year, the ISO shall, within five (5) business days after receipt of the Triggering Resource's required notice of intent to commence ICAP market participation, provide notice that ICAP market parameters determined using Case 2B shall apply for the entire Capability Year.

If the Triggering Resource does not provide such required notice of intent to commence ICAP market participation for the May Obligation Procurement Period of such Capability Year, the ISO shall provide notice that ICAP market parameters determined using Case 2A shall be implemented starting with the May Obligation Procurement Period. ICAP market parameters determined using Case 2A shall remain in effect until the Obligation Procurement Period during such Capability Year for which the Triggering Resource, in accordance with Section 5.11.7.3 of this ISO Services Tariff and ISO Procedures, provides the required notice of intent to commence ICAP market participation; provided, however, if the Triggering Resource does not provide such required notice of intent to commence ICAP market participation for an Obligation Procurement Period prior to the November Obligation Procurement Period of such Capability Year, the ISO shall provide notice prior to the start of the Capability Period Auction for the Winter Capability Period encompassed by such Capability Year confirming that ICAP market parameters determined using Case 2A shall remain in effect for the balance of the Capability Year.

If, in accordance with Section 5.11.7.3 of this ISO Services Tariff and ISO Procedures, the Triggering Resource does not provide the required notice of intent to commence ICAP market participation for the May Obligation Procurement Period of such Capability Year but

provides such required notice of its intent to commence ICAP market participation for an Obligation Procurement Period prior to the November Obligation Procurement Period of such Capability Year, the ISO shall provide notice within five (5) business days after receipt of the Triggering Resource's notice of intent to commence ICAP market participation to indicate that the ISO will implement ICAP market parameters determined using Case 2B beginning with the same Obligation Procurement Period designated by the Triggering Resource's notice of intent to commence ICAP market participation. ICAP market parameters determined using Case 2B shall be implemented beginning with the applicable Obligation Procurement Period, as determined in accordance with the immediately preceding sentence, and remain in effect for the balance of the Capability Year.

5.11.7.3 Notice of Intent to Commence ICAP Market Participation

In accordance with the requirements of Section 5.12.1.1 of this ISO Services Tariff, a Triggering Resource shall provide notice of intent to commence ICAP market participation indicating the first Obligation Procurement Period for which the Triggering Resource intends to participate in the ICAP market. A Triggering Resource shall not be permitted to provide such notice until the Triggering Resource (or in the case of an ICAP Supplier holding rights to new UDRs, the transmission facility associated with such new UDRs) successfully completes Trial Operation, as such term is defined in Section 30.1 of Attachment X to the ISO OATT and Section 40.1 of Attachment HH to the ISO OATT.

To commence participation in the ICAP market for the first Obligation Procurement Period of a Capability Period (*i.e.*, May or November), a Triggering Resource must successfully complete Trial Operation and submit the required notice of intent to commence ICAP market

participation for such Obligation Procurement Period by the first business day of the month that is two months prior to the start of such Obligation Procurement Period.

To commence participation in the ICAP market for any Obligation Procurement Period other than the first Obligation Procurement Period of a Capability Period, a Triggering Resource must successfully complete Trial Operation and submit the required notice of intent to commence ICAP market participation for the applicable Obligation Procurement Period by the tenth (10th) calendar day of the month that is two months prior to the start of such Obligation Procurement Period.

The Triggering Resource may, consistent with the requirements of this ISO Services Tariff and ISO Procedures, commence ICAP market participation for any Obligation Procurement Period during the applicable Capability Year; provided, however, that if, in accordance with this Section 5.11.7.3, the Triggering Resource does not provide the required notice of intent to commence ICAP market participation on or before August 10 designating its intent to commence ICAP market participation for an Obligation Procurement Period prior to the November Obligation Procurement Period of such Capability Year, the ISO will not implement ICAP market parameters determined using Case1A (as defined in Section 5.11.7.1 of this ISO Services Tariff) or Case 2B (as defined in Section 5.11.7.2 of this ISO Services Tariff), as applicable, for the Winter Capability Period of such Capability Year.

5.12 Requirements Applicable to Installed Capacity Suppliers

5.12.1 Installed Capacity Supplier Qualification Requirements

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

Storage Resource, Intermittent Power Resource, Limited Control Run-of-River Hydro Resource, Fast-Start Resource, or other permitted type of Generator, consistent with its resource type.

In addition, to qualify as an Installed Capacity Supplier in the NYCA, Energy Limited Resources, Generators, Installed Capacity Marketers, Intermittent Power Resources, Behind-the-Meter Net Generation Resources, Limited Control Run-of-River Hydro Resources and System Resources rated 1 MW or greater, other than External System Resources and Control Area System Resources which have agreed to certain Curtailment conditions as set forth in the third to last paragraph of Section 5.12.1 of this Services Tariff below, Responsible Interface Parties, existing municipally-owned generation, Energy Limited Resources, and Intermittent Power Resources, to the extent those entities are subject to the requirements of Section 5.12.11 of this Services Tariff, Aggregations with a capacity rating of 0.1 MW or greater, and Energy Storage Resources with a nameplate capacity rating that allows a minimum injection to the NYS Transmission System or distribution system of 0.1 MW or greater shall:

5.12.1.1 (i) provide information reasonably requested by the ISO including the name and location of Resources and System Resources; and (ii) in accordance with ISO Procedures and, if applicable, Section 5.11.7 of this ISO Services Tariff, a new Installed Capacity Supplier (including an Installed Capacity Supplier holding rights to new UDRs) shall provide notice of intent to commence participation in the ICAP market indicating the first Obligation Procurement Period for which the new Installed Capacity Supplier intends to participate in the ICAP market;

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

5.12.1.3 abide by the ISO Generator maintenance coordination procedures;

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

5.12.1.5 in accordance with the ISO Procedures,

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

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

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

direct a Resource to exceed its upper operating limit are described in the ISO Procedures;

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

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

5.12.1.8 provide to the ISO regarding any proposed transfers of deliverability rights to be carried out pursuant to Sections 40.18.3 – 40.18.5 of Attachment HH to the ISO OATT: (i) if a request to transfer CRIS at a different location, notice of submission of an Interconnection Request or CRIS-Only Request to transfer CRIS, and (ii) if it is a request to transfer CRIS at the same location, notice of submission of the request.

5.12.1.9 comply with the ISO Procedures;

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

If an External Installed Capacity Supplier is a Generator, or if an External Generator is associated with an Unforced Capacity sale using UDRs or EDRs, then except to the extent such a Generator is unable to Bid in response to the SRE

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

If the External Installed Capacity Supplier that is a Generator, or the External Generator associated with an Unforced Capacity sale using UDRs or EDRs, is not able to Import the quantity of Energy equal to the ICAP equivalent of the UCAP sold from the Generator or EDR to the NYCA, or if a UDR to the Locality, for every hour of an SRE request then, except to the extent already addressed by a declared outage, the Generator shall provide to the ISO an explanation of the reasons for its failure or inability to perform, including evidence demonstrating any physical operating limitations or other operational issues that prevented the Generator from Importing the quantity of Energy equal

to the ICAP equivalent of the UCAP sold from the Generator to the NYCA. To the extent the ISO determines that the information and supporting evidence provided demonstrates that the failure or inability to deliver occurred for reasons outside the control of the External Installed Capacity Supplier or the External Generator associated with an Unforced Capacity sale using UDRs or EDRs, then the deficiency charge set forth in Section 5.12.12.2 of this Services Tariff below that applies solely to violations of this Section 5.12.1.10 of this Services Tariff, shall not be assessed.

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

If the External Installed Capacity Supplier that is a Control Area System Resource is not able to Import the quantity of Energy equal to the ICAP equivalent of the UCAP sold from the Control Area System Resource to the NYCA for every hour of an SRE request then, except to the extent already addressed by a declared outage, the External Installed Capacity Supplier shall

provide to the ISO an explanation of the reasons for its failure or inability to perform, including evidence demonstrating any operational issues that prevented the External Installed Capacity Supplier from Importing the quantity of Energy equal to the ICAP equivalent of the UCAP sold from the Control Area System Resource to the NYCA. To the extent the ISO determines that the information and supporting evidence provided demonstrates that the failure or inability to deliver occurred for reasons outside the External Installed Capacity Supplier's control, then the deficiency charge set forth in Section 5.12.12.2 of this Services Tariff below that applies solely to violations of Section 5.12.1.10 of this Services Tariff shall not be assessed. A Control Area System Resource's failure to Import the quantity of Energy equal to the ICAP equivalent of the UCAP sold due to transmission outage(s) within the External Control Area that prevent delivery of all available Resources shall not be considered outside the External Installed Capacity Supplier's control; such failure shall be deemed a Forced Outage in determining the amount of UCAP that may be supplied by the Control Area System Resource, in accordance with ISO Procedures.

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

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

5.12.1.11.1 Generators providing Energy under contracts executed and effective on or before November 18, 1999 (including PURPA contracts) in which the power purchasers do not control the operation of the supply source but would be responsible for penalties for being off-schedule, with the exception of Generators under must-take PURPA contracts executed and effective on or before November 18, 1999, who have not provided telemetering to their local TO and historically have not been eligible to participate in the NYPP market, which will continue to be treated as TO Load modifiers under the ISO-administered markets;

5.12.1.11.2 Existing topping turbine Generators and extraction turbine Generators producing Energy resulting from the supply of steam to the district steam system located in New York City (LBMP Zone J) in operation on or before November 18, 1999 and/or Generators used in replacing or repowering steam supplies from such units (in accordance with good engineering and economic design) that cannot follow schedules, up to a maximum total of 533 MW of such units; and

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

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

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

5.12.1.14 Energy Limited Resources, Energy Storage Resources, Aggregations comprised entirely of Energy Storage Resources, DER Aggregations, and Aggregations that are Energy Limited Resources must elect an Energy Duration Limitation, as described in Section 5.12.14 of this Services Tariff.

The ISO shall inform each potential Installed Capacity Supplier that the ISO must receive and approve DMNC or DMGC data, as applicable of its approved DMNC or DMGC ratings for

the Summer Capability Period and the Winter Capability Period in accordance with the ISO Procedures.

Requirements to qualify as Installed Capacity Suppliers for External System Resources and Control Area System Resources located in External Control Areas that have agreed not to Curtail the Energy associated with such Installed Capacity shall be established in the ISO Procedures.

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

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

5.12.2 Additional Provisions Applicable to External Installed Capacity Suppliers

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

5.12.2.1 Provisions Addressing the Applicable External Control Area

External Generators, External System Resources, and Control Area System Resources qualify as Installed Capacity Suppliers if they demonstrate to the satisfaction of the NYISO that the Installed Capacity Equivalent of their Unforced Capacity is deliverable to the NYCA; in the case of an entity using a UDR to meet a Locational Minimum Installed Capacity Requirement, to the NYCA interface associated with that UDR transmission facility and will not be recalled or curtailed by an External Control Area to satisfy its own Control Area Loads; in the case of an EDR, to the NYCA interface over which it creates increased transfer capability; and in the case of Control Area System Resources, will not be recalled or curtailed by the External Control Area to satisfy its own Control Area Load. External Installed Capacity associated with Import Rights, EDRs or UDRs is subject to the same deliverability requirements applied to Internal Installed Capacity Suppliers associated with UDRs.

5.12.2.2 Additional Provisions Addressing Internal Deliverability and Import Rights

In addition to the provisions contained in Section 5.12.2.1 of this Services Tariff above, External Installed Capacity not associated with UDRs, EDRs, or External CRIS Rights will be subject to the deliverability test in Sections 40.13.8 and 40.13.9 of Attachment HH to the ISO OATT. The deliverability of External Installed Capacity not associated with UDRs, EDRs, or External CRIS Rights will, subject to Section 5.11.7 of this ISO Services Tariff, be evaluated annually as a part of the process that sets import rights for the upcoming Capability Year, to

determine the amount of External Installed Capacity that can be imported to the New York Control Area across any individual External Interface and across all of those External Interfaces, taken together. The External Installed Capacity deliverability test will be performed using the ISO's forecast, for the upcoming Capability Year, of New York Control Area CRIS resources, transmission facilities, and load. Under this process (i) Grandfathered External Installed Capacity Agreements listed in Attachment E of the ISO Installed Capacity Manual, and (ii) the Existing Transmission Capacity for Native Load listed for New York State Electric & Gas Corporation in Table 3 of Attachment L to the ISO OATT, will be considered deliverable within the Rest of State. Additionally, 1090 MW of imports made over the Quebec (via Chateauguay) Interface will be considered to be deliverable until the end of the 2010 Summer Capability Period.

The import limit set for External Installed Capacity not associated with UDRs, EDRs or External CRIS Rights will be set no higher than the amount of imports deliverable into Rest of State that (i) would not increase the LOLE as determined in the upcoming Capability Year IRM consistent with Section 2.7 of the NYISO Installed Capacity Manual, "Limitations on Unforced Capacity Flow in External Control Areas," (ii) are deliverable within the Rest of State Capacity Region when evaluated with the New York Control Area CRIS resources (including EDRs and UDRs) and External CRIS Rights forecast for the upcoming Capability Year, and (iii) would not degrade the transfer capability of any External Other Interface or Internal Other Interface by more than the threshold identified in Section 40.13.9 of Attachment HH to the ISO OATT. Import limits set for External Installed Capacity will reflect the modeling of awarded External CRIS rights, but the awarded External CRIS rights will not be adjusted as part of import limit-

setting process. Procedures for qualifying selling, and delivery of External Installed Capacity are detailed in the Installed Capacity Manual.

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

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

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

survive for the term of the relevant External Installed Capacity contract or until the relevant External Generator is retired.

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

An entity can request to convert a specified number of MW, up to 1090 MW over the Quebec External Interface (via Chateauguay), into External CRIS Rights by making either a Contract Commitment or Non-Contract Commitment that satisfies the requirements of Section 40.13.11.1 of Attachment HH to the ISO OATT. The converted number of MW will not be subject to further evaluation for deliverability within a Cluster Study Deliverability Study under Attachment HH to the ISO OATT, as long as the External CRIS Rights are in effect.

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

5.12.2.3.2 Requests to convert these grandfathered rights must be received by the NYISO on or before 5:00 pm Eastern Time on February 1, 2010, with the following information: (a) a statement that the entity is electing to convert by satisfying the requirements of a Contract Commitment or a Non-Contract Commitment in accordance with Section 40.13.11.1 of Attachment HH to the ISO OATT; (b) the length of the commitment in years; (c) for the Summer Capability Period, the requested number of MW; (d) for the Winter Capability Period, the Specified Winter Months, if any, and the requested number of MW; and (e) a minimum number of MW the entity will accept if granted ("Specified Minimum") for the Summer Capability Period and for all Specified Winter Months, if any.

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

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

$$Rights\ allocated\ to\ entity\ i = 1090 * (MW_i * contract/commitment\ length_i) / \sum_j (MW_j * contract/commitment\ length_j)$$

j = l,…# entities requesting import rights

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

5.12.2.3.5 Any portion of the previously grandfathered 1090 MW not converted through this process will no longer be grandfathered from deliverability.

Previously grandfathered rights converted to External CRIS Rights but then terminated will no longer be grandfathered from deliverability.

5.12.2.4 Offer Cap Applicable to Certain External CRIS Rights

Notwithstanding any other capacity mitigation measures or obligations that may apply, the offers of External Installed Capacity submitted pursuant to a Non-Contract Commitment, as described in Section 40.13.11.1.2 of Attachment HH of the ISO OATT, will be subject to an offer cap in each month of the Summer Capability Period and for all Specified Winter Months. This offer cap will be determined as the higher of:

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

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

5.12.2.5 Annual Election and Must Offer Requirement Applicable to UCAP Associated with an External UDR or EDR Not Returned to the NYCA

Prior to the 2027-2028 Capability Year and in accordance with the ISO Procedures, the holder of External UDR or EDR rights may, by August 1, return to the NYCA a quantity of the External UDRs or EDRs for the upcoming Capability Year to be used in the NYSRC and NYISO reliability studies that determine the NYCA Installed Reserve Margin and the Locational Minimum Installed Capacity Requirements, respectively, for the upcoming Capability Year.

Starting with the 2027-2028 Capability Year and in accordance with the ISO Procedures, the holder of External UDR or EDR rights may, by August 1, return to the NYCA a quantity of the External UDRs or EDRs for each Capability Period in the upcoming Capability Year to be used in the NYSRC and NYISO reliability studies that determine the NYCA Minimum Installed Capacity Requirement and the Locational Minimum Installed Capacity Requirements, respectively, for each Capability Period in the upcoming Capability Year. Starting with the 2027-2028 Capability Year, the UCAP associated with an External UDR or EDR that has not been returned to the NYCA as described above must be offered in each ICAP Spot Market Auction or certified for use in meeting an LSE's NYCA Minimum Unforced Capacity Requirement or Locational Minimum Unforced Capacity Requirement for the Obligation Procurement Period in accordance with Section 5.14.1.1 of this Services Tariff and the ISO Procedures. The sanctions for failure to offer or certify the UCAP associated with an External UDR or EDR that has not been returned to the NYCA in accordance with this section of the Services Tariff are set forth in Section 5.12.12.4 of this Services Tariff.

5.12.3 Installed Capacity Supplier Outage Scheduling Requirements

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

rescheduling of their outages to ensure that projected Operating Reserves over the upcoming year are adequate.

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

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

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

5.12.4 Required Certification for Installed Capacity

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

(b) Each Installed Capacity Supplier holding rights to UDRs or EDRs from an External Control Area must confirm to the ISO, in accordance with ISO Procedures, that it will not use as self-supply or offer, and has not sold, Installed

Capacity associated with the quantity of MW for which it has not made its one time capability adjustment year election pursuant to Section 5.11.4 of this Services Tariff (if applicable).

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

5.12.5 Operating Data Reporting Requirements

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

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

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

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

5.12.5.2 Control Area System Resources

To qualify as Installed Capacity Suppliers in the NYCA, Control Area System Resources, or the purchasers of Unforced Capacity associated with those Resources, shall submit CARL Data and actual system failure occurrences data to the ISO each month in accordance with the ISO Procedures.

5.12.5.3 Transmission Projects Granted Unforced Capacity Deliverability Rights

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

5.12.5.4 Transmission Projects Granted External-to ROS Deliverability Rights

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

5.12.5.5 Co-located Storage Resources

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

5.12.6 Capacity Calculations, Operating Data Default, Value and Collection

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

The ISO shall calculate the amount of Net-ICAP for each Behind-the-Meter Net Generation Resource as the Adjusted DMGC of the Generator of the Behind-the-Meter Net Generation Resource minus the Resource's Adjusted Host Load in accordance with this Tariff and ISO Procedures.

5.12.6.1.1 Adjusted DMGC

The ISO's calculation of the Adjusted DMGC of a Behind-the-Meter Net Generation Resource shall be the least of: (i) its DMGC for the Capability Period; (ii) its Adjusted Host Load plus its applicable Injection Limit; and (iii) its Adjusted Host Load plus the number of MW of CRIS it has obtained, as determined in accordance with Section 40 of Attachment HH to the ISO OATT and ISO Procedures.

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

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

5.12.6.1.2 Adjusted Host Load

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

The Adjusted Host Load shall be calculated by the ISO on an annual basis prior to the start of the Summer Capability Period and in accordance with ISO Procedures, based upon the

Behind-the-Meter Net Generation Resource's Average Coincident Host Load for the prior Summer Capability Period and the Winter Capability Period before that.

5.12.6.1.2.1 Average Coincident Host Load

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

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

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

5.12.6.1.2.2 Determination of Adjusted Host Load

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

5.12.6.2 UCAP Calculations

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

The amount of Unforced Capacity that each Generator, except for the Generator of a Behind-the-Meter Net Generation Resource, System Resource, Energy Limited Resource, Special Case Resource, and municipally-owned generation is authorized to supply in the NYCA shall be based on the ISO's calculations of individual Equivalent Demand Forced Outage Rates. The amount of Unforced Capacity that a Generator that is participating as a part of a Co-located Storage Resource is authorized to supply in the NYCA shall account for reductions to the CSR Scheduling Limits, or the unavailability of the associated facilities, in accordance with ISO Procedures.

The amount of Unforced Capacity that each Energy Storage Resource, Aggregation that is comprised entirely of Energy Storage Resources, and DER Aggregation is authorized to supply in the NYCA shall be based on the individual availability of the Energy Storage Resource or the availability of the Aggregation in the Real-Time Market and calculated by the ISO in

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

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

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

The ISO shall calculate separate Summer and Winter Capability Period Unforced Capacity values for each Special Case Resource and update them periodically using a twelve-month calculation in accordance with ISO Procedures. The calculation for each Generator,

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

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

The ISO shall calculate separate Summer and Winter Capability Period Unforced Capacity values for Intermittent Power Resources and Limited Control Run-of-River Hydro Resources and update them seasonally as described in ISO Procedures.

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

5.12.6.2.1 Exceptions

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

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

5.12.6.2.2 UCAP Adjustment for Partial Firm Units

Starting with the Capability Year beginning May 1, 2026, Installed Capacity Suppliers may receive a Capacity Accreditation Factor comprising multiple Capacity Accreditation Factors derived from multiple corresponding Capacity Accreditation Resource Classes calculated as a MW weighted average of the different levels of elected firm fuel MW for each portion of the respective Capacity Accreditation Resource Class.

5.12.6.3 Default Unforced Capacity

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

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

5.12.6.4 Exception for Certain Equipment Failures

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

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

The ISO shall calculate the availability of the External interface associated with each project granted EDRs, in accordance with ISO Procedures. The availability factor (percentage) of the interface will be used to reduce the amount of EDRs for which Unforced Capacity may be

offered. This calculation is distinct from and in addition to the calculation the ISO performs for each Installed Capacity Resource qualified for use with EDRs.

5.12.7 Availability Requirements

Subsequent to qualifying, each Installed Capacity Supplier shall, except as noted in Sections 5.12.1 and 5.12.11 of this Services Tariff, on a daily basis: (i) schedule a Bilateral Transaction; (ii) Bid Energy in each hour of the Day-Ahead Market in accordance with the requirements set forth in this Section 5.12.7 of this Services Tariff; or (iii) notify the ISO of any outages.

Installed Capacity Suppliers with Energy Duration Limitations less than or equal in length to the number of hours comprising the applicable Peak Load Window must on a daily basis during the Peak Load Window and for at least the number of consecutive hours that correspond to its Energy Duration Limitation or for the entirety of the Peak Load Window for an Energy Storage Resource: (i) schedule a Bilateral Transaction; (ii) Bid Energy in the Day-Ahead Market in accordance with the applicable provisions of Section 5.12.1 of this Services Tariff; or (iii) notify the ISO of any outages. Installed Capacity Suppliers with Energy Duration Limitations greater in length than the number of hours comprising the Peak Load Window must on a daily basis during the entirety of the applicable Peak Load Window and for additional hours immediately preceding and following the Peak Load Window covering the remaining hours of the Installed Capacity Supplier's Energy Duration Limitation that are not captured in the Peak Load Window, as specified in ISO Procedures: (i) schedule a Bilateral Transaction; (ii) Bid Energy in the Day-Ahead Market in accordance with the applicable provisions of Section 5.12.1 of this Services Tariff; or (iii) notify the ISO of any outages.

The ISO may adjust the Peak Load Window that Installed Capacity Suppliers with Energy Duration Limitations will be responsible for the scheduling, bidding, or notification requirements with scheduling or bidding in hours outside the Peak Load Window in Section 5.12.14 of this Services Tariff. An RMR Generator can only schedule a Bilateral Transaction to the extent expressly authorized in its RMR Agreement.

Prior to the Capability Year beginning May 1, 2025, the total amount of Energy that an Installed Capacity Supplier subject to Services Tariff Section 5.12.7 schedules, bids, or declares to be unavailable on a given day must equal or exceed the Installed Capacity Equivalent of the Unforced Capacity it supplies. Starting with the Capability Year beginning May 1, 2025, and except as expressly provided under Section 5.12.7.2 of this Services Tariff, the total amount of Energy that an Installed Capacity Supplier schedules, Bids at a Normal Upper Operating Limit, or declares to be unavailable on a given day must equal or exceed the Installed Capacity Equivalent of the Unforced Capacity it supplies.

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

Storage Resources with an Energy Duration Limitation greater in length than the number of hours comprising the applicable Peak Load Window must on a daily basis and for each hour beyond the hours that the Energy Storage Resources must schedule, bid, or declare to be unavailable in accordance with paragraph three of Section 5.12.7 of this Services Tariff: (i) Bid in the Day-Ahead Market in accordance with the applicable provisions of Section 5.12.1of this Services Tariff; or (ii) notify the ISO of any outages, the maximum of the Energy Storage Resource's (a) negative Installed Capacity Equivalent, or (b) Lower Operating Limit. The amount scheduled, Bid, and/or declared to be unavailable must reflect the Energy Storage Resource's entire withdrawal operating range.

5.12.7.1 Co-located Storage Resource Availability Requirements

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

Storage Resource's applicable Services Tariff Section 5.12.7 hourly Bid, Schedule, or Notify obligation.

5.12.7.2 Upper Operating Limit Bidding Exemptions

An Installed Capacity Supplier's Day Ahead Market Bid is not required to include a Normal Upper Operating Limit as set forth in Section 5.12.7 of this Services Tariff if it meets one of the following two limited circumstances:

5.12.7.2.1 Bids for Combined Cycle Generators qualified to sell Operating Reserves using Duct-Firing technology shall include either an Emergency Upper Operating Limit or a Normal Upper Operating Limit at a level equal to or greater than its Installed Capacity Equivalent of Unforced Capacity supplied. If the Normal Upper Operating Limit is less than the unit's Installed Capacity Equivalent of Unforced Capacity supplied, then the difference between the Emergency Upper Operating Limit and Normal Upper Operating Limit shall not exceed the increase in the unit's maximum output level that results from the operation of duct burners.

5.12.7.2.2 Bids for block-loaded Combustion Turbine Generators with Peak-Firing capability shall include either an Emergency Upper Operating Limit or a Normal Upper Operating Limit at a level equal to or greater than its Installed Capacity Equivalent of Unforced Capacity supplied. If the Normal Upper Operating Limit is less than the unit's Installed Capacity Equivalent of Unforced Capacity supplied, then the difference between the Emergency Upper Operating Limit and Normal Upper Operating Limit shall not exceed the increase in the unit's maximum output level that results from operating the resource in peak-firing mode.

5.12.8 Unforced Capacity Sales

Each Installed Capacity Supplier will, after satisfying the deliverability requirements set forth in the applicable provisions of Attachments S, X, Z, or HH to the ISO OATT, be authorized to supply an amount of Unforced Capacity during each Obligation Procurement Period, based on separate seasonal Unforced Capacity calculations performed by the ISO for the Summer and Winter Capability Periods and subject to Section 5.11.7 of this ISO Services Tariff. Unforced Capacity may be sold in six-month strips or in monthly or multi-monthly segments.

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

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

If an Energy Limited Resource's, Generator's, System Resource's, Control Area System Resource's, or Aggregation's DMNC rating, or the DMGC rating of a Generator of a Behind-the-Meter Net Generation Resource, if applicable, is determined to have increased during an Obligation Procurement Period, pursuant to testing procedures described in the ISO Procedures, the amount of Unforced Capacity that it shall be authorized to supply in that or future Obligation Procurement Periods shall also be increased on a prospective basis in accordance with the schedule set forth in the ISO Procedures provided that it first has satisfied the deliverability

requirements set forth in the applicable provisions of Attachments S, X, Z, or HH to the ISO OATT.

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

New Resources and Resources that have increased their Capacity since the previous Winter Capability Period due to changes in their generating equipment and/or Demand Reduction capabilities may, after satisfying the deliverability requirements set forth in the applicable provisions of Attachments S, X, Z or HH to the ISO OATT, qualify to supply Unforced Capacity on a foregoing basis during the Winter Capability Period based upon a DMNC test, or the DMGC test of a Resource of a Behind-the-Meter Net Generation Resource,

that is performed and reported to the ISO after September 1 and prior to the beginning of the Winter Capability Period DMNC Test Period. The Resource will be required to verify the claimed DMNC or DMGC rating by performing an additional test during the Winter Capability Period DMNC Test Period. Any shortfall between the amount of Unforced Capacity certified by the Resource for the Winter Capability Period and the amount verified during the Winter Capability Period DMNC Test Period will be subject to deficiency charges pursuant to Section 5.14.2 of this Services Tariff. The deficiency charges will be applied to no more than the difference between the Resource's previous Winter Capability Period Unforced Capacity and the amount of Unforced Capacity equivalent the Resource supplied for the Winter Capability Period.

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

5.12.9 Sales of Unforced Capacity by System Resources

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

5.12.10 Curtailment of External Transactions In-Hour

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

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

5.12.11.1 Responsible Interface Parties

Responsible Interface Parties may qualify as Installed Capacity Suppliers, without having to comply with the daily bidding, scheduling, and notification requirements set forth in Section 5.12.7 of this Services Tariff, if their Special Case Resources are available to operate at the direction of the ISO in order to reduce Load from the NYS Transmission System and/or the distribution system for a minimum of four (4) consecutive hours each day, following notice of

the potential need to operate twenty-one (21) hours in advance if notification is provided by 3:00 P.M. ET, or twenty-four (24) hours in advance otherwise, and a notification to operate two (2) hours ahead. Special Case Resources will be considered to have a four (4) hour Energy Duration Limitation to align with their obligation. In order for a Responsible Interface Party to enroll an SCR that uses an eligible Local Generator, any amount of generation that can reduce Load from the NYS Transmission System and/or distribution system at the direction of the ISO that was produced by the Local Generator during the hour coincident with the NYCA or Locality peaks, upon which the LSE Unforced Capacity Obligation of the LSE that serves that SCR is based, must be accounted for when the LSE's Unforced Capacity Obligation for the upcoming Capability Year is established. Responsible Interface Parties must provide this generator data in accordance with ISO Procedures so that the ISO can adjust upwards the LSE Unforced Capacity Obligation to prevent double-counting.

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

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

ISO, pursuant to ISO Procedures, to reflect the Load serving equivalence of the hours they are actually available.

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

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

Each Special Case Resource enrolled in a Capability Period shall demonstrate its maximum enrolled megawatt value at least once in the Capability Period via performance in a mandatory event or performance test in accordance with Installed Capacity Manual Section 4.12. When a Special Case Resource is enrolled in a Capability Period and transitions to become a Distributed Energy Resource within that same Capability Period, it shall demonstrate its maximum enrolled megawatt value via performance in a mandatory event or in a performance test, provided, however, that if no such mandatory event occurs prior to the Special Case Resource becoming a Distributed Energy Resource, the Distributed Energy Resource shall participate in a performance test in accordance with the ISO's Aggregation Manual. Responsible Interface Parties are not eligible to receive Energy payments, as described in this Section

5.12.11.1 of this Services Tariff, for Demand Reductions caused by Distributed Energy Resources performing in a performance test. When a Demand Side Resource that is participating, or has participated, in a DER Aggregation and seeks to become a Special Case Resource, the Resource's Average Coincident Load shall be calculated in accordance with the provisions of this Section 5.12.11.1 and its subparts of this Services Tariff.

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

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

Provided the Responsible Interface Party supplies evidence of such reductions in seventy-five (75) days, the ISO shall pay the Responsible Interface Party that, through their Special Case Resources, caused a verified Load reduction in response to (i) an ISO request to perform due to a forecast reserve shortage (ii) an ISO declared Major Emergency State, (iii) an ISO request to perform made in response to a request for assistance for Load relief purposes or as a result of a Local Reliability Rule, or (iv) a test called by the ISO, for such Load reduction, in accordance with ISO Procedures. Subject to performance evidence and verification, in the case of a response pursuant to clauses (i), (ii), of (iii) of this subsection, Suppliers that schedule Responsible Interface Parties shall be paid the zonal Real-Time LBMP for the period of requested performance or four (4) hours, whichever is greater, in accordance with ISO Procedures.

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

Transmission Owners that require assistance from enrolled Special Case Resources with Local Generators larger than 100 kW and Special Case Resources with Loads capable of being interrupted upon demand for Load relief purposes or as a result of a Local Reliability Rule, shall direct their requests for assistance to the ISO for implementation consistent with the terms of this

section. Within Load Zone J, participation in response to an ISO request to perform made as a result of a request for assistance from a Transmission Owner for less than the total number of Special Case Resources, for Load relief purposes or as a result of a Local Reliability Rule, in accordance with ISO Procedures, shall be voluntary and the responsiveness of the Special Case Resource shall not be taken into account for performance measurement.

5.12.11.1.1 Special Case Resource Average Coincident Load

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

Beginning with the Winter 2011-2012 Capability Period and thereafter, the ISO shall use the average of the highest twenty (20) one-hour peak Loads of the SCR taken from the Load data reported for the Capability Period SCR Load Zone Peak Hours during the Prior Equivalent Capability Period, and taking into account the resource's reported verified Load reduction in a Transmission Owner's demand response program in hours coincident with any of these hours, to create a SCR ACL baseline. The ISO will post to its website the Capability Period SCR Load Zone Peak Hours for each zone ninety (90) days prior to the beginning of the Capability Period for which the ACL will be in effect.

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

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

Beginning with the Summer 2014 Capability Period, in addition to the requirement for RIPs to report each SCR's metered Load values that occurred during the Capability Period SCR Load Zone Peak Hours, in accordance with this Services Tariff and ISO Procedures during the enrollment process, any qualifying increase in a SCR's Load that will be supplied by the NYS Transmission System and/or distribution system may be reported as an Incremental ACL, subject to the limitations and verification reporting requirements provided in Section 5.12.11.1.5 of this Services Tariff and in accordance with ISO Procedures. Incremental ACL values must be reported using the required enrollment file that may be uploaded by the RIP during each month's

enrollment period. RIPs may not report Incremental ACL values for any SCRs that are enrolled in the Capability Period with a Provisional ACL.

A reduction in a SCR's Load that is supplied by the NYS Transmission System and/or distribution system and meets the criteria for a SCR Change of Status must be reported as a SCR Change of Status as provided by Section 5.12.11.1.3 of this Services Tariff and in accordance with ISO Procedures.

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

5.12.11.1.2 Use of a Provisional Average Coincident Load

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

Beginning with the Summer 2014 Capability Period, a SCR may be enrolled using a Provisional ACL in lieu of an ACL when one of the following conditions has been determined by the ISO to apply: (i) the SCR has not previously been enrolled with the ISO for the seasonal Capability Period for which the SCR enrollment with a Provisional ACL is intended, (ii) the

SCR was enrolled with a Provisional ACL in the Prior Equivalent Capability Period and was required to report fewer than twenty (20) hours of metered Load verification data that correspond with the Capability Period SCR Load Zone Peak Hours based on the meter installation date of the SCR, (iii) the RIP attempting to enroll the SCR with a Provisional ACL is not the same RIP that enrolled the SCR in the Prior Equivalent Capability Period and interval billing meter data for the SCR from the Prior Equivalent Capability Period is not obtainable by the enrolling RIP and not available to be provided to the enrolling RIP by the ISO. The Provisional ACL may be applicable to a SCR for a maximum of three (3) consecutive Capability Periods when enrolled with the same RIP, beginning with the Capability Period in which the SCR is first enrolled by the RIP.

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

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

Any SCR enrolled with a Provisional ACL shall be subject to actual in-period verification. A Verified ACL shall be calculated by the ISO using the top twenty (20) one-hour peak Loads reported for the SCR from the Capability Period SCR Load Zone Peak Hours that are applicable to verify the Provisional ACL in accordance with ISO Procedures and taking into account the resource's reported verified Load reductions in a Transmission Owner's demand response program that are coincident with any of the applicable Capability Period SCR Load Zone Peak Hours.

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

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

5.12.11.1.3.1 SCR Change of Load

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

5.12.11.1.3.2 SCR Change of Status

The Responsible Interface Party shall report any SCR Change of Status in accordance with ISO Procedures. The ISO shall adjust the reported ACL of the SCR for a reported SCR Change of Status to the Net ACL, for all prospective months to which the SCR Change of Status is applicable. When a SCR Change of Status is reported under clause (i), (ii) or (iii) within the definition of a Qualified Change of Status Condition and the SCR has sold capacity, the SCR

shall be evaluated for a potential shortfall under Section 5.14.2 of this Services Tariff. Failure by the RIP to report a SCR Change of Status shall be evaluated as a potential shortfall under Section 5.14.2 of this Services Tariff and evaluated for failure to report under Section 5.12.12.2 of this Services Tariff.

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

5.12.11.1.4 Average Coincident Load of an SCR Aggregation

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

5.12.11.1.5 Use of an Incremental Average Coincident Load

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

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

The ISO shall adjust the ACL of the SCR for an Incremental ACL for all months for which the Incremental ACL is reported by the RIP. For resources reporting an Incremental ACL, the Net ACL shall equal the enrolled ACL plus the reported Incremental ACL less any

applicable SCR Change of Status and shall be the basis for the upper limit of ICAP for which the RIP may enroll the SCR during the Capability Period.

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

Following the Capability Period for which a SCR has been enrolled with an Incremental ACL, the RIP shall provide the hourly metered Load verification data that corresponds to the Monthly SCR Load Zone Peak Hours identified by the ISO for all months in which an Incremental ACL value was reported for the SCR. For each month for which verification data was required to be reported, the ISO shall calculate a Monthly ACL that will be used in the calculation of a Verified ACL. The Monthly ACL shall equal the average of the SCR's top twenty (20) one-hour metered Load values that correspond with the applicable Monthly SCR Load Zone Peak Hours, and taking into account the resource's reported verified Load reduction in a Transmission Owner's demand response program in hours coincident with any of these hours. The Verified ACL shall be the average of the two (2) highest Monthly ACLs during the Capability Period in which the SCR was enrolled with an Incremental ACL within the same Capability Period.

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

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

A Special Case Resource that was required to perform in the first performance test in the Capability Period in accordance with ISO Procedures and was subsequently enrolled using an Incremental ACL and an increase in the amount of Installed Capacity that the SCR is eligible to sell, shall be required to demonstrate performance against the maximum amount of eligible Installed Capacity reported for the SCR in the second performance test in the Capability Period. Performance in this test shall be measured from the Net ACL. Performance in both performance tests shall be used in calculation of the resource's performance factor and all associated performance factors, deficiencies and penalties. If the RIP fails to report the performance for a

resource that was required to perform in the second performance test in the Capability Period: (a) the resource will be assigned a performance of zero (0) for the test hour, and (b) the RIP shall be evaluated for failure to report under Section 5.12.12.2 of this Services Tariff.

5.12.11.2 Existing Municipally-Owned Generation

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

5.12.11.3 Energy Limited Resources

An Energy Limited Resource or an Aggregation that is comprised entirely of a single Resource-type Energy Limited Resource may, consistent with the deliverability requirements set forth in Attachment HH to the ISO OATT, qualify as an Installed Capacity Supplier if it Bids its Installed Capacity Equivalent into the Day-Ahead Market each day and if it is able to provide the Energy equivalent of the Unforced Capacity for the number of consecutive hours that correspond to its Energy Duration Limitation each day. Energy Limited Resources or Aggregations that are Energy Limited Resources shall also Bid a Normal Upper Operating Limit or Emergency Upper

Operating Limit, as applicable, designating their desired operating limits. Energy Limited Resources or Aggregations that are Energy Limited Resources that are not scheduled in the Day-Ahead Market to operate at a level above their bid-in upper operating limit, may be scheduled in the RTC, or may be called in real-time pursuant to a manual intervention by ISO dispatchers, who will account for the fact that Energy Limited Resource or an Aggregation that is an Energy Limited Resource may not be capable of responding.

5.12.11.4 Intermittent Power Resources

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

5.12.11.5 Installed Capacity Suppliers with an Energy Duration Limitation

A Resource with an Energy Duration Limitation may, consistent with the deliverability requirements set forth in Attachment HH to the ISO OATT, qualify as an Installed Capacity Supplier with an Energy Duration Limitation if it Bids its Installed Capacity Equivalent into the Day-Ahead Market each day and if it is able to provide the Energy equivalent of the Unforced Capacity for the number of consecutive hours that correspond to its Energy Duration Limitation

each day. Installed Capacity Suppliers with an Energy Duration Limitation shall also Bid a Normal Upper Operating Limit or Emergency Upper Operating Limit, as applicable, designating their desired operating limits. Installed Capacity Suppliers with an Energy Duration Limitation that are not scheduled in the Day-Ahead Market to operate at a level above their bid-in upper operating limit, may be scheduled in the RTC, or may be called in real-time pursuant to a manual intervention by ISO dispatchers, who will account for the fact that Installed Capacity Suppliers with an Energy Duration Limitation may not be capable of responding.

5.12.12 Sanctions Applicable to Installed Capacity Suppliers and Transmission Owners

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

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

5.12.12.1 Sanctions for Failing to Provide Required Information

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

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

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

If a TO fails to provide the information required by Subsection 5.11.3 of this Services Tariff in a timely fashion, the ISO may take the following actions: On the first day that required

information is late, the ISO shall notify the TO that required information is past due and that it reserves the right to impose financial sanctions if the information is not provided by the end of the following day. Starting on the third day that the required information is late, the ISO may impose a daily financial sanction up to $5,000 a day. Starting on the tenth day that required information is late, the ISO may impose a daily financial sanction up to $10,000.

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

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

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

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

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

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

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

Where:

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

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

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

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

If an Installed Capacity Supplier's failure to fully comply with this Services Tariff would, in addition to being assessed a deficiency charge calculated in accordance with the formula set forth above, also permit the ISO to impose a different deficiency charge or a financial sanction under this Section 5.12.12.2 of this Services Tariff, or to impose a deficiency charge for a shortfall under Section 5.14.2.2 of this Services Tariff, then the ISO shall only impose the

penalty for failure to comply with Section 5.12.1.10 of this Services Tariff on the Installed Capacity Supplier for the hour(s) in which the Installed Capacity Supplier failed to meet its obligations under Section 5.12.1.10 of this Services Tariff.

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

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

this Services Tariff, multiplied by up to one and one-half times the applicable Market-Clearing Price of Unforced Capacity determined in the ICAP Spot Market Auction for each such month.

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

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

5.12.12.3 Annual Firm Fuel Reconciliation Amount for Failing to Provide Elected Firm Fuel Capacity

Starting with the Capability Year beginning May 1, 2026, an Installed Capacity Supplier that has elected to enter any amount of MW in the firm fuel Capacity Accreditation Resource Class may be subject to a Firm Fuel Sanction or Settlement Adjustment, as those terms are defined in Section 5.12.12.3.3 of this Services Tariff, if it experiences a Forced Outage(s) and/or de-rate(s) due to lack of fuel during one or more of the months of December, January or February (individually, “Winter Performance Month” and, collectively, “Winter Performance

Period") in accordance with Section 5.12.15.2 of this Services Tariff for any MW level it has elected. The ISO shall determine whether to assess either a Firm Fuel Sanction or a Settlement Adjustment based on whether such Forced Outage(s) and/or de-rate(s) due to lack of fuel were within or outside the Installed Capacity Supplier's control, as described in Section 5.12.12.3.3 of this Services Tariff. A Settlement Adjustment shall be applied if an Installed Capacity Supplier that has elected to enter any amount of MW in the firm fuel Capacity Accreditation Resource Class fails to establish or maintain an operating plan and related supply, transportation, and/or replenishment agreements in accordance with Section 5.12.15.2 of this Services Tariff for any MW level it has elected. Any Firm Fuel Sanction and Settlement Adjustment assessed shall be a component of an annual firm reconciliation amount ("Annual Firm Fuel Reconciliation Amount") calculated in accordance with this Section 5.12.12.3 of the Services Tariff.

5.12.12.3.1 If an Installed Capacity Supplier (i) experiences a Forced Outage(s) and/or derate(s) due to lack of fuel in a Winter Performance Month and/or (ii) fails to establish or maintain the operating plan and related supply, transportation, and/or replenishment agreements for the MW level it has elected in accordance with Section 5.12.15.2 of this Services Tariff and the ISO Procedures, the ISO shall calculate a UCAP base differential amount ("Base Differential Amount") for each month in the subject Capability Year. The Base Differential Amount for month *m* shall be calculated by multiplying (i) the ratio of the UCAP the Installed Capacity Supplier sold in month *m* to the amount of UCAP the Installed Capacity Supplier was qualified to sell in month *m* and (ii) the amount of UCAP the Installed Capacity Supplier was qualified to sell in month *m* minus the amount of UCAP the Installed Capacity Supplier would have been qualified to sell in month *m* if the Installed Capacity Supplier had not elected to enter any MW in the firm fuel Capacity Accreditation Resource Class.

5.12.12.3.2 For each month in which a Base Differential Amount is calculated, the ISO shall calculate an Incremental Firm Fuel Revenue specific to month *m*. The Incremental Firm Fuel Revenue shall be calculated as the Base Differential Amount for month *m* times the applicable Market-Clearing Price of UCAP using the applicable ICAP Demand Curve for the ICAP Spot Market Auction for month *m*.

5.12.12.3.3 For each Winter Performance Month in which an Installed Capacity Supplier elects to participate in the firm fuel Capacity Accreditation Resource Class and experiences a Forced Outage(s) and/or derate(s) due to lack of fuel or fails to establish or maintain an operating plan and related supply, transportation, and/or replenishment agreements for the MW level it has elected in accordance with Section 5.12.15.2 of this Services Tariff and the ISO Procedures, the ISO shall assign either a "Firm Fuel Sanction Multiplier" or a "Settlement Adjustment Multiplier," as described in this subsection.

5.12.12.3.3.1 If an Installed Capacity Supplier had one or more Forced Outage(s) and/or de-rate(s) due to lack of fuel in a Winter Performance Month in the subject Capability Year for the MW level it has elected that the ISO determines were *within* the Installed Capacity Supplier's control, as described in the ISO Procedures, the ISO shall apply a firm fuel sanction multiplier for that Installed Capacity Supplier for that Winter Performance Month equal to 1.5 ("Firm Fuel Sanction Multiplier"). Otherwise, the Firm Fuel Sanction Multiplier for that Installed Capacity Supplier for that Winter Performance Month will be zero.

5.12.12.3.3.2 If an Installed Capacity Supplier had one or more Forced Outage(s) and/or de-rate(s) due to lack of fuel in a Winter Performance Month in the subject Capability Year, but the ISO determines that none of the Forced Outage(s) and/or de-rate(s) due to lack of fuel in a Winter Performance Month in the subject Capability Year for the MW level it has elected were

within the Installed Capacity Supplier's control, as described in the ISO Procedures, the ISO shall apply a settlement adjustment multiplier for that Winter Performance Month equal to 1.0 ("Settlement Adjustment Multiplier").

5.12.12.3.3.3 If the ISO determines that an Installed Capacity Supplier failed to establish an operating plan and related supply, transportation, and/or replenishment agreements for the MW level it has elected in accordance with Section 5.12.15.2 of this Services Tariff and the ISO Procedures, the ISO shall apply a Settlement Adjustment Multiplier equal to 1.0 for all three Winter Performance Months of the Winter Performance Period in the subject Capability Year; however, if the Installed Capacity Supplier experiences one or more Forced Outage(s) and/or de-rate(s) due to lack of fuel for the MW level it has elected for any given Winter Performance Month within such Winter Performance Period that the ISO determines were *within* the Installed Capacity Supplier's control, the Installed Capacity Supplier will be subject to a Firm Fuel Sanction Multiplier for that month as described in Section 5.12.12.3.3.1 of this Services Tariff above, and the Settlement Adjustment Multiplier for that Installed Capacity Supplier for that Winter Performance Month will be zero.

5.12.12.3.3.4 If the ISO determines that an Installed Capacity Supplier fails to maintain an operating plan and related supply, transportation, and/or replenishment agreements for the MW level elected in accordance with Section 5.12.15.2 of this Services Tariff and the ISO Procedures, the ISO shall apply a Settlement Adjustment Multiplier equal to 1.0 for that Winter Performance Month and any remaining Winter Performance Months within the Winter Performance Period in the subject Capability Year; however, if the Installed Capacity Supplier experiences one or more Forced Outage(s) and/or de-rate(s) due to lack of fuel for the MW level it has elected for that Winter Performance Month or any remaining Winter Performance Months

within such Winter Performance Period that the ISO determines were *within* the Installed Capacity Supplier's control, the Installed Capacity Supplier will be subject to a Firm Fuel Sanction Multiplier for that month as described in Section 5.12.12.3.3.1 of the Services Tariff above, and the Settlement Adjustment Multiplier for that Installed Capacity Supplier for that Winter Performance Month will be zero.

5.12.12.3.3.5 If none of the conditions described in Sections 5.12.12.3.3.2 through 5.12.12.3.3.4 of this Services Tariff causes the Settlement Adjustment Multiplier for an Installed Capacity Supplier for a given Winter Performance Month to be set to a value of 1.0, then that Settlement Adjustment Multiplier for that Installed Capacity Supplier will be set to a value of zero for that Winter Performance Month.

5.12.12.3.4 For each Installed Capacity Supplier that has elected the firm fuel Capacity Accreditation Resource Class and is subject to a Firm Fuel Sanction and/or Settlement Adjustment as described in this Section 5.12.12.3 of this Services Tariff, the ISO shall calculate an average multiplier for the subject Capability Year that is the sum of the Firm Fuel Sanction and Settlement Adjustment Multipliers assigned to each of the Winter Performance Months within the subject Capability Year, which will then be divided by the number of months in the Winter Performance Period ("Average Multiplier"), as described in the ISO Procedures.

5.12.12.3.5 Such an Installed Capacity Supplier's monthly firm fuel reconciliation amount for a given month shall then be calculated as the Incremental Firm Fuel Revenue multiplied by its Average Multiplier for the subject Capability Year ("Monthly Firm Fuel Reconciliation Amount").

5.12.12.3.6 If an Installed Capacity Supplier that has elected any amount of MW in the firm fuel Capacity Accreditation Resource Class experiences a Forced Outage(s) and/or derate(s)

due to lack of fuel in a Winter Performance Month or fails to establish or maintain the operating plan and related supply, transportation, and/or replenishment agreements for the MW level it has elected in accordance with Section 5.12.15.2 of this Services Tariff and the ISO Procedures, the ISO shall calculate an Annual Firm Fuel Reconciliation Amount for that the subject Capability Year associated with such elected MW level. The Installed Capacity Supplier's Annual Firm Fuel Reconciliation Amount shall be calculated as the sum of the twelve (12) Monthly Firm Fuel Reconciliation Amounts for the subject Capability Year. The Installed Capacity Supplier will be assessed the Annual Firm Fuel Reconciliation Amount, which shall be applied to the Installed Capacity Supplier's sales of UCAP for each month within the applicable Capability Year, in accordance with ISO Procedures.

5.12.12.4 Sanctions for Failure to Offer UCAP Associated with an External UDR or EDR Not Returned to the NYCA

Starting with the 2027-2028 Capability Year, the UCAP associated with an External UDR or EDR that has not been returned to the NYCA as described in Section 5.12.2.5 shall be offered in each ICAP Spot Market Auction or certified for use in meeting an LSE's NYCA Minimum Unforced Capacity Requirement or Locational Minimum Unforced Capacity Requirement for the Obligation Procurement Period in accordance with Section 5.14.1.1 of this Services Tariff and the ISO Procedures.

If the holder of an External UDR or EDR fails to offer or certify UCAP associated with an External UDR or EDR that has not been returned to the NYCA in any ICAP Spot Market Auction during the subject Capability Period, it shall pay the ISO an amount for all months of the subject Capability Period equal to the product of (i) 1.5 times the applicable ICAP Spot Market Auction price and (ii) the quantity by which the UCAP associated with the given External UDR or EDR that has not been returned to the NYCA exceeds the minimum amount of UCAP associated with the

given External UDR or EDR that has not been returned to the NYCA that is offered or certified during any month of the subject Capability Period.

If the NYISO determines that the holder of an External UDR or EDR is required to pay the ISO for (1) the failure to offer or certify the UCAP associated with an External UDR or EDR that has not been returned to the NYCA in any ICAP Spot Market Auction during the subject Capability Period as described in this section of the Services Tariff as well as (2) the failure to offer or sell Mitigated UCAP or External Sale UCAP in accordance with Section 23.4.5.4.2 of this Services Tariff, then the holder of the applicable External UDR or EDR shall pay the ISO the larger of these two sanction amounts.

5.12.13 Aggregations

5.12.13.1 Resources Entering and Changing Aggregations

A qualified Installed Capacity Supplier, which meets the requirements to participate in an Aggregation, may enter an Aggregation pursuant to the rules set forth in Section 4.1.10.3 of this Services Tariff.

When an Installed Capacity Supplier that is a Special Case Resource enters an Aggregation to become a Distributed Energy Resource within the same Capability Period, the maximum Installed Capacity that an Aggregator can declare for the Distributed Energy Resource shall be the upper limit of Installed Capacity calculated for the Special Case Resource in accordance with Section 5.12.11.1.1 of this Services Tariff. When an existing Special Case Resource enters an Aggregation and becomes a Distributed Energy Resource at the beginning of a Capability Period (*i.e.*, begins participating as a Distributed Energy Resource on May 1 or November 1), the maximum Installed Capacity that an Aggregator can declare for that Distributed Energy Resource shall be the upper limit of Installed Capacity calculated for the

Special Case Resource for the immediately prior like Capability Period, calculated in accordance with Section 5.12.11.1.1 of this Services Tariff, if such value was calculated.

When a Generator with an approved in-period DMNC rating enters an Aggregation to become a Distributed Energy Resource, the maximum Installed Capacity that an Aggregator can declare for the Distributed Energy Resource shall be the minimum of the Generator's approved in-period DMNC rating and the Generator's CRIS.

Individual Distributed Energy Resources may elect to leave their current Aggregation and join a new Aggregation pursuant to the Resources Changing Aggregation rules set forth in this Services Tariff section below and in Section 4.1.10.3 of this Services Tariff. The Installed Capacity of a Distributed Energy Resource that enters a new Aggregation will be assigned to the new Aggregation on a monthly basis beginning on the first day of the month in which the Distributed Energy Resource enters the new Aggregation. The Installed Capacity of a Distributed Energy Resource that exits an Aggregation will be removed from the Aggregation on the last day in which the Distributed Energy Resource is registered in the Aggregation. The specific processes for transferring a Distributed Energy Resource and its Installed Capacity to another Aggregation are located in the ISO Procedures.

An individual resource within an Aggregation may only change from participating in a homogenous Aggregation that is not a DER Aggregation to participating in a DER Aggregation at the beginning of a Capability Year, provided that the Aggregation notifies the ISO by August 1 of the year prior to the beginning of the Capability Year. An individual resource within an Aggregation may only change from participating in a DER Aggregation to participating in a homogeneous Aggregation that is not a DER Aggregation at the beginning of a Capability Year,

provided that the Aggregation notifies the ISO by August 1 of the year prior to the beginning of the Capability Year. If the composition of a homogeneous Aggregation that is not a DER Aggregation changes during a Capability Year such that the homogeneous Aggregation that is not a DER Aggregation would no longer qualify as a homogeneous Aggregation that is not a DER Aggregation, the homogeneous Aggregation that is not a DER Aggregation will maintain the qualifications as a homogeneous Aggregation that is not a DER Aggregation for the remainder of the Capability Year, and, it will have to elect (i) a different Aggregation by August 1, (ii) to participate in the ISO Administered Markets as a Generator, if qualified, or (iii) to leave the ISO Administered Markets for the following Capability Year. If the composition of a DER Aggregation changes during a Capability Year such that the DER Aggregation would no longer qualify as a DER Aggregation, the DER Aggregation will maintain the qualifications as a DER Aggregation for the remainder of the Capability Year, and, it will have to elect (i) a different Aggregation by August 1, (ii) to participate in the ISO Administered Markets as a Generator, if qualified, or (iii) to leave the ISO Administered Markets for the following Capability Year. An individual Distributed Energy Resource seeking to participate in the ISO-administered Installed Capacity auctions that has previously acted as a retail load modifier may only register as an Installed Capacity Supplier for the upcoming Capability Year, provided that Resource notified the ISO of its intention to become an Installed Capacity Supplier by August 1 of the year prior to the start of the Capability Year and provided the output data in accordance with ISO Procedures.

5.12.13.2 Time-stacking Resources in an Aggregation

An Aggregator may sequentially stack individual Distributed Energy Resources within an Aggregation in order to meet the Energy Duration Limitations specified in Section 5.12.14 of this Services Tariff. In addition to the requirements and obligations described in Section 5.12.13

of this Services Tariff, the following rules apply to an Aggregation that seeks to sequentially stack individual Distributed Energy Resources:

5.12.13.2.1 each individual Distributed Energy Resource must be able to provide Energy for a minimum of one 1-hour block each day;

5.12.13.2.2 individual Distributed Energy Resources duration will be rounded-down to the nearest hour and stacked in whole-hour increments;

5.12.13.2.3 Time-stacked Aggregations will be qualified for the amount of Capacity it can sustain over the run-time requirement; and

The specific processes related to time-stacking Distributed Energy Resources in an Aggregation are located in the ISO Procedures.

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

Installed Capacity Suppliers will have their Adjusted ICAP calculated pursuant to Section 5.12.14.2 of this Services Tariff using the applicable Capacity Accreditation Factor. In accordance with ISO Procedures, Resources with a limited run-time must elect an Energy Duration Limitation that is less than or equal to the Resource's ability to demonstrate sustained output at its qualified MW amount and will use the corresponding Capacity Accreditation Factor.

Resources with an Energy Duration Limitation must fulfill the availability requirements given in Section 5.12.7 of this Services Tariff for the duration of the Peak Load Window.

5.12.14.1 Reserved for Future Use

5.12.14.2 Adjusted Installed Capacity

An Installed Capacity Supplier's Unforced Capacity shall reflect the applicable Capacity Accreditation Factor of its Capacity Accreditation Resource Class. The Installed Capacity

Supplier's Adjusted Installed Capacity is equal to its Installed Capacity multiplied by its applicable Capacity Accreditation Factor. If an existing Resource wishes to join an Aggregation, or, if a Resource or Aggregation wishes to elect a different Energy Duration Limitation than its current duration, it must inform the ISO by August 1 preceding the upcoming Capability Year.

5.12.14.3 Periodic Review of Capacity Values Accreditation Factors

Starting with the Capability Year that begins in May 2024 and occurring every year, the ISO shall review the existing Capacity Accreditation Factors established for each Capacity Accreditation Resource Class and assess for the upcoming Capability Year the marginal reliability contributions of each Capacity Accreditation Resource Class toward meeting NYSRC resource adequacy requirements. The annual review shall: (i) unless provided otherwise in Section 5.11.7 of this ISO Services Tariff, use the Installed Reserve Margin/Locational Minimum Installed Capacity Requirement study model that is approved by the NYSRC for the upcoming Capability Year as a starting database, (ii) be performed at the conditions that reflect the expected NYCA system that meets the resource adequacy criterion, (iii) develop Capacity Accreditation Factors for all Capacity Accreditation Resource Classes that reflect the marginal reliability contributions toward meeting NYSRC resource adequacy requirements, and (iv) be performed for Rest of State, G-J Locality (excluding Load Zone J), NYC Locality, and Long Island Locality to the extent there exists an Installed Capacity Supplier or projected Installed Capacity Supplier in the given Capacity Accreditation Resource Classes in the applicable location, as specified in ISO Procedures and, if applicable, the requirements of Section 5.11.7 of the ISO Services Tariff.

In conjunction with this review, the ISO shall review the Peak Load Window associated with the bidding requirements for Resources with Energy Duration Limitations and modify the Peak Load Window accordingly, pursuant to ISO Procedures.

5.12.15 Capacity Accreditation Resource Class Characteristic Elections

Starting with the Capability Year beginning May 1, 2026, an Installed Capacity Supplier that operates by utilizing natural gas and/or fuel oil may elect to fully or partially participate in the firm fuel Capacity Accreditation Resource Class, in accordance with the ISO Procedures.

5.12.15.1 An Installed Capacity Supplier that elects to fully or partially participate in the firm fuel Capacity Accreditation Resource Class for the 2026-2027 Capability Year must notify the ISO of the MW capability it elects for participation by November 1, 2025. In each subsequent Capability Year, an Installed Capacity Supplier that elects to fully or partially participate in a firm fuel Capacity Accreditation Resource Class must notify the ISO of the MW capability it elects for participation by August 1 of the calendar year preceding the subject Capability Year (*e.g.*, by August 1, 2026 for the 2027-2028 Capability Year). An Installed Capacity Supplier that operates on natural gas and/or fuel oil that does not elect to enter some or all of its MW capability in the firm fuel Capacity Accreditation Resource Class or any other Capacity Accreditation Resource Class for which it is eligible shall have its undesignated MW capability included in the non-firm fuel Capacity Accreditation Resource Class.

5.12.15.2 An Installed Capacity Supplier that elects to enter all or part of its MW capability in the firm fuel Capacity Accreditation Resource Class shall have an operating plan and related supply, transportation, and/or replenishment agreements in place and effective by December 1 of the subject Capability Year sufficient to provide firm fuel capability at the elected

MW level, in accordance with the ISO Procedures. For a Generator utilizing natural gas as its fuel, such agreements include supply and/or transportation agreements (or equivalent). For a Generator utilizing fuel oil, such agreements include supply and replenishment agreements (or equivalent). The Installed Capacity Supplier must maintain a sufficient operating plan and agreements for the entire Winter Performance Period and, if and where necessary, (i) make any such modifications or updates to its operating plan and any such agreements to remain in compliance with this Section 5.12.15.2 of this Services Tariff, in accordance with the ISO Procedures and (ii) notify the NYISO thereof within five (5) business days.

5.12.15.3 If the Installed Capacity Supplier fails to establish the necessary operating plan and related supply, transportation, and/or replenishment agreements required by Section 5.12.15.2 of this Services Tariff by December 1 of the subject Capability Year, it shall notify the ISO by December 1 of the subject Capability Year, and it will be subject to the provisions of Section 5.12.15.4 of this Services Tariff. If changes to the Installed Capacity Supplier's operating plan and related supply, transportation, and/or replenishment agreements occur, the Installed Capacity Supplier shall notify the ISO, in accordance with Section 5.12.15.2 of this Services Tariff. If the Installed Capacity Supplier cannot make modifications to support its elected firm MW amount, the Installed Capacity Supplier shall notify the ISO, in accordance with Section 5.12.15.2 of this Services Tariff, and it will be subject to the provisions of Section 5.12.15.4 of this Services Tariff.

5.12.15.4 If the ISO determines that an Installed Capacity Supplier that elected the firm fuel Capacity Accreditation Resource Class for all or part of its MW capability has not provided service that meets the requirements to participate in such Capacity Accreditation Resource Class, as set forth in the ISO Procedures, for the MW level it has elected due to lack of fuel or

otherwise failing to comply with the provisions of Sections 5.12.15.2 and 5.12.15.3 of this Services Tariff, the Installed Capacity Supplier shall be subject to an Annual Firm Fuel Reconciliation Amount. The Annual Firm Fuel Reconciliation Amount shall be calculated in accordance with Section 5.12.12.3 of this Services Tariff.

5.12.15.5 If an Installed Capacity Supplier fails to meet the notification requirements of Section 5.12.15.2 of this Services Tariff, it may be subject to the provisions of Section 5.12.15.4 of this Services Tariff, and the ISO shall refer such failure to the Commission consistent with the ISO's Market Monitoring Plan (Section 30 of this Services Tariff). If the ISO, in consultation with its Market Monitoring Unit, suspects that an Installed Capacity Supplier's operating plan and related supply, transportation, and/or replenishment agreements do not support its elected firm MW amount, the ISO shall refer the matter to the Commission consistent with the ISO's Market Monitoring Plan (Section 30 of this Services Tariff). If the ISO is able to determine the Installed Capacity Supplier's operating plan and/or agreements do not support its elected firm MW amount, the Installed Capacity Supplier shall be subject to the provisions of Section 5.12.15.4 of this Services Tariff.

5.13 Installed Capacity Auctions

5.13.1 General Auction Requirements

The ISO will administer Installed Capacity auctions to accommodate LSEs' and Installed Capacity Suppliers' efforts to enter into Unforced Capacity Transactions and to give LSEs an opportunity to acquire sufficient Unforced Capacity to meet their respective LSE Unforced Capacity Obligations. The ISO shall conduct regular auctions, at the request of an LSE, at the times specified in this section and the ISO Procedures, and may conduct additional auction as necessary.

Installed Capacity Suppliers, LSEs and Installed Capacity Marketers that are Customers under this Tariff will be allowed to participate in Installed Capacity auctions, provided that they satisfy the creditworthiness requirements set forth in Attachment K of the ISO OATT. Unforced Capacity purchased in Installed Capacity auctions may not be sold for the purposes of meeting Installed Capacity requirements imposed by operators of External Control Areas. Offers to sell and bids to purchase Unforced Capacity shall be made in $/kW for the time period appropriate to the auction. The ISO shall impose no limits on Bids or offers in any auction, except to the extent required by any applicable Capacity market mitigation measures.

Installed Capacity Suppliers that wish to participate in an ISO-administered auction must submit completed certification forms to the ISO in accordance with the ISO Procedures, demonstrating that their Unforced Capacity has not been committed to a Bilateral Transaction.

The ISO Procedures shall specify the dates by which the ISO will post the results of Installed Capacity auctions. The ISO Procedures shall ensure that there are at least four business days between the time that auction results from monthly auctions are posted and the dates that LSEs are required to demonstrate the quantity of Unforced Capacity that has been obtained for

the upcoming Obligation Procurement Period, pursuant to Section 5.11.2 of this Tariff. LSEs holding Unforced Capacity which they want credited against their LSE Unforced Capacity Obligations must certify such Unforced Capacity when submitting their Installed Capacity certifications.

5.13.2 Capability Period Auction

A Capability Period Auction will be conducted no later than thirty (30) days prior to the start of each Capability Period in which Unforced Capacity will be purchased and sold for the entire duration of the Capability Period. The exact date of the Capability Period Auction shall be established in the ISO Procedures. The Capability Period Auction is intended to facilitate long-term Unforced Capacity transactions between Market Participants.

The Capability Period Auction will be conducted and solved simultaneously to purchase Unforced Capacity which may be used by an LSE toward all components of its LSE Unforced Capacity Obligation for each Obligation Procurement Period. Participation shall consist of: (i) LSEs seeking to purchase Unforced Capacity; (ii) any other entity seeking to purchase Unforced Capacity; (iii) qualified Installed Capacity Suppliers; and (iv) any other entity that owns excess Unforced Capacity.

Buyers that are awarded Unforced Capacity shall pay the applicable Market-Clearing Price of Unforced Capacity in the Capability Period Auction. Sellers that are selected to provide Unforced Capacity shall receive the applicable Market-Clearing Price of Unforced Capacity in the Capability Period Auction.

The results of the Capability Period Auction will be made available to Market Participants at the time specified in the ISO Procedures, which shall be prior to the start of the Monthly Auction held prior to the beginning of each Capability Period.

5.13.3 Monthly Auctions

Monthly Auctions will be held during which Unforced Capacity may be purchased and sold for the forthcoming Obligation Procurement Period, and any other month or months remaining in the Capability Period, as specified in the ISO Procedures. The exact dates of each Monthly Auction shall be established in the ISO Procedures. Each Monthly Auction is intended to facilitate Unforced Capacity transactions between Market Participants.

Each Monthly Auction will be conducted and solved simultaneously to purchase Unforced Capacity which may be used by an LSE toward all components of its LSE Unforced Capacity Obligation for each Obligation Period. Participation shall consist of: (i) LSEs seeking to purchase Unforced Capacity; (ii) any other entity seeking to purchase Unforced Capacity; (iii) qualified Installed Capacity Suppliers; and (iv) any other entity that owns excess Unforced Capacity.

Buyers that are awarded Unforced Capacity shall pay the applicable Market-Clearing Price of Unforced Capacity in the Monthly Auction. Sellers that are selected to provide Unforced Capacity shall receive the applicable Market-Clearing Price.

The results of each Monthly Auction will be made available to Market Participants in accordance with the ISO Procedures.

5.13.4 Detailed Installed Capacity Auction Description

Additional detail concerning the ISO’s Installed Capacity auction procedures are provided in the ISO Procedures.

5.14 Installed Capacity Spot Market Auction and Installed Capacity Supplier Deficiencies

5.14.1 LSE Participation in the ICAP Spot Market Auction

5.14.1.1 ICAP Spot Market Auction

When the ISO conducts each ICAP Spot Market Auction it will account for all Unforced Capacity that each NYCA LSE has certified for use in the NYCA to meet its NYCA Minimum Unforced Capacity Requirement or Locational Minimum Unforced Capacity Requirement, as applicable, whether purchased through Bilateral Transactions or in prior auctions. The ISO shall receive offers of Unforced Capacity that has not previously been purchased through Bilateral Transactions or in prior auctions from qualified Installed Capacity Suppliers for the ICAP Spot Market Auction. Interim Service Providers that are required to keep their generating unit(s) in service must offer at $0.00/kW-month all of their Unforced Capacity into each ICAP Spot Market Auction conducted for each Obligation Procurement Period associate with a month in which it is to receive compensation under Rate Schedule 8 of the Services Tariff. If an Interim Service Provider that is required to keep its generating unit(s) in service is expressly precluded from offering all or a portion of its UCAP into an ICAP Spot Market Auction because it is obligated to provide capacity pursuant to a bilateral contract that is effective at the time of the ICAP Spot Market Auction, and was executed and effective before the NYISO received a Generator Deactivation Notice the Interim Service Provider (such contract a “Preexisting Capacity Bilateral”), then the Interim Service Provider shall only be required to offer the amount of its Unforced Capacity into that ICAP Spot Market Auction that it is not expressly required to provide pursuant to the terms of the such Preexisting Capacity Bilateral. The quantity of Unforced Capacity an Interim Service Provider that is required to keep its generating unit(s) in service is required to offer in accordance with this paragraph is the “ISP UCAP MW”. The ISO shall also receive offers of

Unforced Capacity from any LSE for any amount of Unforced Capacity that the LSE has in excess of its NYCA Minimum Unforced Capacity Requirement or Locational Minimum Unforced Capacity Requirement, as applicable. Unforced Capacity that will be exported from the New York Control Area during the month for which Unforced Capacity is sold in an ICAP Spot Market Auction shall be certified to the NYISO by the certification deadline for that auction.

The ISO shall conduct an ICAP Spot Market Auction to purchase Unforced Capacity which shall be used by an LSE toward all components of its LSE Unforced Capacity Obligation for each Obligation Procurement Period immediately preceding the start of each Obligation Procurement Period. The exact date of the ICAP Spot Market Auction shall be established in the ISO Procedures. All LSEs shall participate in the ICAP Spot Market Auction. In the ICAP Spot Market Auction, the ISO shall submit monthly bids on behalf of all LSEs at a level per MW determined by the ICAP Demand Curves established in accordance with this Tariff and the ISO Procedures. The ICAP Spot Market Auction will set the LSE Unforced Capacity Obligation for each NYCA LSE in accordance with the ISO Procedures.

The ICAP Spot Market Auction will be conducted and solved simultaneously for Unforced Capacity that may be used by an LSE towards all components of its LSE Unforced Capacity Obligation for that Obligation Procurement Period using the applicable ICAP Demand Curves, as established in accordance with the ISO Procedures. LSEs that are awarded Unforced Capacity in the ICAP Spot Market Auction shall pay to the ISO the Market-Clearing Price of Unforced Capacity determined in the ICAP Spot Market Auction using the applicable ICAP Demand Curve. The ISO shall pay each Installed Capacity Supplier that is selected to provide

Unforced Capacity the Market-Clearing Price determined in the ICAP Spot Market Auction using the ICAP Demand Curve applicable to its offer.

5.14.1.2 Demand Curve and Adjustments

ICAP Demand Curves will be established to determine (a) the locational component of LSE Unforced Capacity Obligations for each Locality (b) the locational component of LSE Unforced Capacity Obligations for any New Capacity Zone, and (c) the total LSE Unforced Capacity Obligations for all LSEs. Beginning with the ICAP Demand Curves applicable for the 2025-2026 Capability Year, ICAP Demand Curves will, in accordance with ISO Procedures, be established for each Capability Period encompassed by a Capability Year.

The ICAP Demand Curves for the 2025-2026 Capability Year shall be established at the following points (in accordance with Section 5.14.1.2.2, the ICAP Demand Curve values for the 2024-2025 Capability Year were determined pursuant to the annual update for such Capability Year and the ICAP Demand Curves for the 2026-2027 through 2028-2029 Capability Years will be determined pursuant to the respective annual updates for each such Capability Year; provided, however, that for the 2026-2027 Capability Year, the ICAP Demand Curves applicable for all months covered by the 2026-2027 Winter Capability Period shall be as set forth in Section 5.14.1.2.1 of this ISO Services Tariff):

	Capability Year				
	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029
NYCA	Posted on the ISO website on or before 11/30/2023	Summer Max @ $21.69 $5.72 @ 100% $0.00 @ 112% Winter	To be posted on the ISO website on or before 11/30/2025*	To be posted on the ISO website on or before 11/30/2026	To be posted on the ISO website on or before 11/30/2027

		Max @ $16.39 $4.33 @ 100% $0.00 @ 112%			
G-J Locality	Posted on the ISO website on or before 11/30/2023	Summer Max @ $23.25 $6.15 @ 100% $0.00 @ 115% Winter Max @ $19.99 $5.29 @ 100% $0.00 @ 115%	To be posted on the ISO website on or before 11/30/2025*	To be posted on the ISO website on or before 11/30/2026	To be posted on the ISO website on or before 11/30/2027
NYC	Posted on the ISO website on or before 11/30/2023	Summer Max @ $41.30 $17.37 @ 100% $0.00 @ 118% Winter Max @ $34.83 $14.64 @ 100% $0.00 @ 118%	To be posted on the ISO website on or before 11/30/2025*	To be posted on the ISO website on or before 11/30/2026	To be posted on the ISO website on or before 11/30/2027
LI	Posted on the ISO website on or before 11/30/2023	Summer Max @ $28.16 $6.80 @ 100% $0.00 @ 118% Winter Max @ $36.37 $8.78 @ 100% $0.00 @ 118%	To be posted on the ISO website on or before 11/30/2025*	To be posted on the ISO website on or before 11/30/2026	To be posted on the ISO website on or before 11/30/2027

	Note: All dollar figures are in terms of $/kW-month of ICAP and all percentages are in terms of the applicable NYCA Minimum Installed Capacity Requirement and the applicable Locational Minimum Installed Capacity Requirement. The defined points describe a line segment with a negative slope that will result in higher values for percentages less than 100% of the applicable NYCA Minimum Installed Capacity Requirement or the applicable Locational Minimum Installed Capacity Requirement ("reference point") with the maximum value for each ICAP Demand Curve established at 1.5 times the estimated monthly localized levelized cost to develop a new peaking plant in each Locality or in Rest of State, as applicable. * Notwithstanding anything to the contrary in the ISO Tariffs and ISO Procedures, the ICAP Demand Curves for all months covered by the 2026-2027 Winter Capability Period shall be as set forth in Section 5.14.1.2.1 of this ISO Services Tariff. The ICAP Demand Curves previously posted on the ISO website by November 30, 2025 for the 2026 Summer Capability Period shall apply for all months covered by the 2026 Summer Capability Period.

In subsequent years, the costs assigned by the ICAP Demand Curves to the applicable NYCA Minimum Installed Capacity Requirement, the applicable Locational Minimum Installed Capacity Requirement, and any applicable Indicative NCZ Minimum Installed Capacity Requirement, will be defined by the results of the independent review conducted pursuant to this section. The ICAP Demand Curves will be translated into Unforced Capacity terms in accordance with the ISO Procedures. Beginning with the 2024-2025 Capability Year, the aforementioned translation shall utilize the applicable derating factor of the peaking plant used to establish each ICAP Demand Curve, as determined during the periodic review conducted pursuant to Section 5.14.1.2.2.

5.14.1.2.1 ICAP Demand Curves for the 2026-2027 Winter Capability Period

Notwithstanding anything to the contrary in the ISO Tariffs and ISO Procedures, for the 2026-2027 Capability Year, the ICAP Demand Curves applicable for all months covered by the 2026-2027 Winter Capability Period shall be established at the following points:

ICAP Demand Curve	2026-2027 Winter Capability Period

NYCA	Max @ $14.16 $4.13 @ 100% $0.00 @ 112%
G-J Locality	Max @ $13.23 $3.69 @ 100% $0.00 @ 115%
NYC	Max @ $21.10 $10.18 @ 100% $0.00 @ 118%
LI	Max @ $30.82 $8.36 @ 100% $0.00 @ 118%
Note: All dollar figures are in terms of $/kW-month of ICAP and all percentages are in terms of the applicable NYCA Minimum Installed Capacity Requirement and Locational Minimum Installed Capacity Requirement. The defined points describe a line segment with a negative slope that will result in higher values for percentages less than 100% of the NYCA Minimum Installed Capacity Requirement or the Locational Minimum Installed Capacity Requirement ("reference point") with the maximum value for each ICAP Demand Curve established at 1.5 times the estimated monthly localized levelized cost to develop a new peaking plant in each Locality or in Rest of State, as applicable.	

For the 2026-2027 Capability Year, the ICAP Demand Curves previously posted to the ISO website by November 30, 2025 for the 2026 Summer Capability Period shall apply for all months covered by the 2026 Summer Capability Period.

5.14.1.2.2 Periodic Reviews of ICAP Demand Curves

A periodic review of the ICAP Demand Curves shall be performed every four (4) years in accordance with the ISO Procedures to: (i) identify the methodologies and inputs used for determining the ICAP Demand Curves for the four Capability Years covered by the periodic review; and (ii) establish the ICAP Demand Curves for the first Capability Year covered by the periodic review.

The periodic review shall assess: (i) the current localized levelized embedded cost of a peaking plant in each NYCA Locality, the Rest of State, and any New Capacity Zone, to meet minimum capacity requirements (for purposes of this Section 5.14.1.2.2 hereinafter referred to as the "peaking plant gross cost"); and (ii) the likely projected annual Energy and Ancillary Services revenues of the peaking plant for the first Capability Year covered by the periodic review, net of the costs of producing such Energy and Ancillary Services (for purposes of this Section 5.14.1.2.2 hereinafter referred to as the "net Energy and Ancillary Services revenue offset"), including the methodology and inputs for determining such projections for the four Capability Years covered by the periodic review.

Except for the ICAP Demand Curves set forth in Section 5.14.1.2.1 that apply for all months covered by the 2026-2027 Winter Capability Period, the cost and revenues of the peaking plant used to set the reference point and maximum value for each ICAP Demand Curve shall be determined under conditions in which the available capacity is equal to the sum of (a) the minimum Installed Capacity requirement and (b) the peaking plant's capacity equal to the number of MW specified in the periodic review and used to determine all costs and revenues (for purposes of this Section 5.14.1.2.2 hereinafter referred to as the "prescribed level of excess").

For purposes of determining the prescribed level of excess prior to the 2027-2028 Capability Year, the minimum Installed Capacity requirement for each Locality shall be equal to the Locational Minimum Installed Capacity Requirement in effect for the year in which the independent consultant's final report (referenced below in Section 5.14.1.2.2.4.6) is issued; for the NYCA, equal to the NYCA Minimum Installed Capacity Requirement based on the Installed Reserve Margin accepted by the Commission and applicable to the Capability Year which begins in the Capability Year in which the independent consultant's final report is issued; and for any

New Capacity Zone, equal to the Indicative NCZ Locational Minimum Installed Capacity Requirement determined by the NYISO in accordance with Section 5.16.3 of this Services Tariff.

For the purposes of determining the prescribed level of excess for the ICAP Demand Curves applicable for the 2027 Summer Capability Period, the minimum Installed Capacity requirement for each Locality shall be equal to the Locational Minimum Installed Capacity Requirement in effect for the 2026-2027 Capability Year and for the NYCA, equal to the NYCA Minimum Installed Capacity Requirement in effect for the 2026-2027 Capability Year. For the purposes of determining the prescribed level of excess for the 2027-2028 Winter Capability Period ICAP Demand Curves, the minimum Installed Capacity requirement for each Locality shall be equal to the Locational Minimum Installed Capacity Requirement that would have been in effect for the 2026-2027 Winter Capability Period based on the methodology for determining the Locational Minimum Installed Capacity Requirements for the 2027-2028 Winter Capability Period as described in the ISO Procedures and for the NYCA, equal to the NYCA Minimum Installed Capacity Requirement that would have been in effect for the 2026-2027 Winter Capability Period based on the methodology for determining the NYCA Minimum Installed Capacity Requirement for the 2027-2028 Winter Capability Period as described in the ISO Procedures.

For the purposes of determining the prescribed level of excess starting with the ICAP Demand Curves applicable for the 2028-2029 Capability Year, the minimum Installed Capacity requirement for the applicable Capability Period for each Locality shall be equal to the Locational Minimum Installed Capacity Requirement in effect for the like Capability Period in the prior Capability Year; for the applicable Capability Period for the NYCA, equal to the NYCA Minimum Installed Capacity Requirement for the like Capability Period in the prior

Capability Year; and for the applicable Capability Period for any New Capacity Zone, equal to the Indicative NCZ Locational Minimum Installed Capacity Requirement for the like Capability Period determined by the NYISO in accordance with Section 5.16.3 of this Services Tariff.

Except for the ICAP Demand Curves set forth in Section 5.14.1.2.1 that apply for all months covered by the 2026-2027 Winter Capability Period, for the ICAP Demand Curves applicable prior to the 2027-2028 Capability Year, the determination of the reference point and maximum value for each ICAP Demand Curve for a given Capability Year shall account for conditions reflecting the prescribed level of excess and seasonal differences in the amount of capacity available in ICAP Spot Market Auctions. For a given Capability Year, the Capability Period in which more capacity is expected to be available in the ICAP Spot Market Auctions due to seasonal differences in availability shall utilize conditions that account for the prescribed level of excess and the additional capacity available due to such seasonal differences, while the Capability Period in which less capacity is expected to be available in the ICAP Spot Market Auctions due to seasonal differences in availability shall utilize conditions that account for only the prescribed level of excess (for purposes of this Section 5.14.1.2.2 hereinafter referred to as the "reference point assumed excess conditions"). Starting with the ICAP Demand Curves applicable for 2027-2028 Capability Year, the determination of the reference point and maximum value for each ICAP Demand Curve for a given Capability Year shall account for conditions reflecting the prescribed level of excess for each Capability Period.

The periodic review shall also assess (i) the appropriate shape and slope of the ICAP Demand Curves, and the associated point at which the dollar value of the ICAP Demand Curves should decline to zero (for purposes of this Section 5.14.1.2.2 of this Services Tariff, the associated point at which the dollar value of the ICAP Demand Curves should decline to zero is

hereinafter referred to as the "zero crossing point"); (ii) the appropriate translation of the annual net revenue requirement of the peaking plant determined from the factors specified above, into monthly values; for the ICAP Demand Curves applicable prior to the 2027-2028 Capability Year, such translation shall take into account seasonal differences in the amount of capacity available in the ICAP Spot Market Auctions in accordance with the methodology set forth in Section 5.14.1.2.2.3; and (iii) the escalation factor and inflation component of the escalation factor applied to the peaking plant gross cost, including the methodology and inputs for determining such values.

Beginning with the ICAP Demand Curves applicable for 2025-2026 Capability Year, the translation of the annual net revenue requirement of each applicable peaking plant into monthly values, in accordance with the ISO Procedures, shall result in the determination of ICAP Demand Curves for each Capability Period encompassed by the Capability Year for which such ICAP Demand Curves will be in effect. For the ICAP Demand Curves applicable prior to the 2027-2028 Capability Year, the translation of the annual net revenue requirement of each peaking plant into monthly values shall also account for seasonal reliability risks in determining the portion of the annual net revenue requirement to be recovered during each Capability Period under the reference point assumed excess conditions. For the ICAP Demand Curves applicable starting with the 2027-2028 Capability Year, the translation of the annual net revenue requirement of each peaking plant into monthly values shall also account for seasonal reliability risks in determining the portion of the annual net revenue requirement to be recovered during each Capability Period for conditions reflecting the prescribed level of excess for each Capability Period. In accordance with the ISO Procedures, seasonal reliability risks shall be accounted for based on the percentage of loss of load risk attributed to each Capability Period as identified in

the results produced by the preliminary base case model approved by the NYSRC for determining the NYCA Installed Reserve Margin applicable to the Capability Year for which the applicable ICAP Demand Curves will be in effect. For the ICAP Demand Curves applicable prior to the 2027-2028 Capability Year, the translation of each annual net revenue requirement into monthly values shall also be subject to maximum and minimum percentages of the allowable portion of the annual net revenue requirement recoverable in each Capability Period under the reference point assumed excess conditions. For the ICAP Demand Curves applicable starting with the 2027-2028 Capability Year, the translation of each annual net revenue requirement into monthly values shall also be subject to maximum and minimum percentages of the allowable portion of the annual net revenue requirement recoverable in each Capability Period for conditions reflecting the prescribed level of excess for each Capability Period. The applicable maximum and minimum allowable percentage values shall initially be set at 65 percent and 35 percent, respectively. Beginning with the periodic review that includes establishment of the ICAP Demand Curves applicable for the 2029-2030 Capability Year, each periodic review shall assess such maximum and minimum allowable percentage values. Any adjustments to the maximum and minimum allowable percentage values shall be identified in the filing referenced in Section 5.14.1.2.2.4.11 below and remain fixed for the entire period covered by the applicable periodic review.

For purposes of this periodic review, a peaking unit is defined as the unit with technology that results in the lowest fixed costs and highest variable costs among all other units' technology that are economically viable, and a peaking plant is defined as the number of units (whether one or more) that constitute the scale identified in the periodic review.

In the filing referenced in Section 5.14.1.2.2.4.11 below, the ISO will: (i) identify the methodologies and inputs used for determining the ICAP Demand Curves for the four Capability Years covered by the periodic review; and (ii) propose the ICAP Demand Curves for the first Capability Year covered by the periodic review. Except for the ICAP Demand Curves set forth in Section 5.14.1.2.1 that apply for all months covered by the 2026-2027 Winter Capability Period, for the subsequent three Capability Years covered by the periodic review, the ISO will establish the ICAP Demand Curves for each such Capability Year by updating the following factors in advance of each such subsequent Capability Year: (i) the peaking plant gross cost in accordance with Section 5.14.1.2.2.1; (ii) the net Energy and Ancillary Services revenue offset in accordance with Section 5.14.1.2.2.2; (iii) for the ICAP Demand Curves applicable prior to the 2027-2028 Capability Year, the seasonal amount of capacity available in ICAP Spot Market Auctions in accordance with Section 5.14.1.2.2.3; (iv) the percentage of reliability risk expected in each Capability Period as described above; (v) starting with the ICAP Demand Curves applicable for the 2027-2028 Capability Year, the zero crossing point of each ICAP Demand Curve applicable for the Winter Capability Period of a given Capability Year; and (vi) starting with the ICAP Demand Curves applicable for the 2027-2028 Capability Year, the prescribed level of excess for each Capability Period of a given Capability Year. Except for the ICAP Demand Curves set forth in Section 5.14.1.2.1 that apply for all months covered by the 2026-2027 Winter Capability Period, the ISO will post the updated ICAP Demand Curves for each subsequent Capability Year covered by the periodic review on or before November 30th of the calendar year immediately preceding the calendar year that includes the start of the Capability Year for which the updated ICAP Demand Curves will apply.

5.14.1.2.2.1 Annual Updates for Peaking Plant Gross Cost

For purposes of the annual updates to the ICAP Demand Curves, the ISO shall determine updated values for the peaking plant gross cost for each peaking plant. Updated values for the peaking plant gross cost shall be determined by application of an escalation factor to the peaking plant gross cost values underlying the ICAP Demand Curves for the first Capability Year covered by the periodic review. The escalation factor shall consist of the following four components: (i) changes in construction material costs ("materials component"); (ii) changes in turbine generator costs ("turbine component"); (iii) changes in labor costs ("labor component"); and (iv) changes in the general cost of goods and services ("general component"). The escalation factor shall be equal to the sum of the: (i) the percentage change in the applicable index for the materials component, multiplied by the applicable weighting factor for such component; (ii) the percentage change in the applicable index for the turbine component, multiplied by the applicable weighting factor for such component; (iii) the percentage change in the applicable index for the labor component, multiplied by the applicable weighting factor for such component; and (iv) the percentage change in the applicable index for the general component, multiplied by the applicable weighting factor for such component. For purposes of determining the percentage change for each component, the values utilized from each applicable index shall be as follows: (i) for indices that publish annual values, the most recently available annual value and the corresponding annual value for the calendar year that contained the most recently available finalized values established by the publisher for the applicable index as of October 1st in the same calendar year as the filing required by Section 5.14.1.2.2.4.11 ("baseline period"); (ii) for indices that publish monthly values, the average value of the three most recently available monthly values and the average value of values for the same three months from the

baseline period; and (iii) for indices that publish quarterly values, the value of the most recently available calendar quarter and the value for the same calendar quarter from the baseline period. The applicable values to be used by the ISO shall be the available finalized values established by the publisher for each index as of October 1st of the same calendar year as the applicable November 30th deadline for posting the updated ICAP Demand Curves. The ISO shall not use any preliminary values published by an index in determining the applicable percentage change for any component of the escalation factor. The weighting factors applied to each component shall be determined as part of the periodic review, identified in the filing required by Section 5.14.1.2.2.4.11 and remain fixed for the entire period covered by the periodic review. The specified index for each component shall likewise be determined as part of the periodic review, identified in the filing required by Section 5.14.1.2.2.4.11 and remain fixed for the entire period covered by the periodic review, unless an index is eliminated, replaced or otherwise terminated by the publisher thereof during the period covered by the periodic review. In such circumstance, the ISO shall utilize the replacement or successor index established by the publisher, if any, or, in the absence of a replacement or successor index, shall select as a replacement a substantially similar index.

5.14.1.2.2.2 Annual Updates for Net Energy and Ancillary Revenue Offset

For purposes of the annual updates to the ICAP Demand Curves, the ISO shall also determine updated values for the net Energy and Ancillary Services revenue offset associated with each peaking plant. Updated values for the net Energy and Ancillary Services revenue offset shall, in part, be determined using a net revenue model that will be developed as part of the periodic review, utilized in determining the net Energy and Ancillary Services revenue offset associated with each peaking plant for the first Capability Year covered by the periodic review,

and made available to stakeholders. For purposes of the annual updates to the ICAP Demand Curves for the remaining three Capability Years covered by the periodic review, the selected model for each peaking plant shall be updated for each such Capability Year with data and inputs that reflect the most recent information for the prior 36 month period ending August 31st of the same calendar year as the applicable November 30th deadline for posting the updated ICAP Demand Curves. The model will, at a minimum, determine whether each peaking plant could earn positive net revenue by producing Energy in each applicable time interval, as determined during the periodic review, based on historical prices and the variable costs for each peaking plant over the prior 36 month period ending August 31st of the same calendar year as the applicable November 30th deadline for posting the updated ICAP Demand Curves, as well as the physical operating characteristics of each peaking plant and any operating hours constraints necessary to address any applicable environmental requirements and/or fuel availability. The commitment and dispatch logic and data sources and/or inputs used by the model, as well as the manner in which the model accounts for net Ancillary Services revenues earned by each peaking plant, the physical operating characteristics of each peaking plant and any operating hours constraints applicable to each peaking plant that are necessary to address any applicable environmental requirements and/or fuel availability, will be determined as part of the periodic review, identified in the filing required by Section 5.14.1.2.2.4.11 and remain fixed for the entire period covered by the periodic review, subject to annual updating of certain data inputs used by the model as described herein.

The model will determine whether each peaking plant could earn positive net revenue by producing Energy in each applicable time interval during the period encompassed by the model in a manner consistent with the following equation:

$$Net\ Energy\ revenue_{z,t} = max(([Output_{z,t} * (LOEAF_{z,t} * LBMP_{z,t})] - MC_{z,t}),0)$$

where:

t = the applicable time interval selected for assessing whether a peaking plant could earn positive net revenue by producing Energy. For Day-Ahead, the time interval shall be one-hour increments. For real-time, the time interval may be either: (1) one-hour increments, or (2) the applicable RTD interval increments. The determination of the applicable selected time interval to be used in real-time for each peaking plant shall: (1) be determined as part of the periodic review based on the physical operating characteristics of each peaking plant; (2) be identified in the filing required by Section 5.14.1.2.2.4.11; and (3) remain fixed for the entire period covered by the periodic review;

$Ouput_{z,t}$ = the quantity of Energy produced by the peaking plant for Load Zone *z* in time interval *t*;

$LOEAF_{z,t}$ = the applicable adjustment factor for Load Zone *z* and time interval *t* used to adjust for the prescribed level of excess applicable for the ICAP Demand Curves for the first Capability Year covered by the periodic review. The adjustment factors shall be determined as part of the periodic review, identified in the filing required by Section 5.14.1.2.2.4.11 and remain fixed for the entire period covered by the periodic review;

$LBMP_{z,t}$ = for Day-Ahead, the Day-Ahead zonal LBMP for Load Zone *z* and time interval *t*. For real-time: (1) if the time interval used for the peaking plant is one-hour increments, the time-weighted/integrated zonal RTD LBMP for Load Zone *z* and time interval *t*; or (2) if the time interval utilized for the peaking plant is the applicable RTD interval increments, the zonal RTD LBMP for Load Zone *z* and time interval *t*;

$MC_{z,t}$ = variable (or short-run marginal) cost of the peaking plant for Load Zone *z* to produce Energy in time interval *t*, calculated as follows:

$$MC_{z,t} = [(HR_{z,t} * Fuel_{z,t}) + VOM_{z,t} + ASC_{z,t} + EC_{z,t} + RS1_{z,t}] * Output_{z,t}$$

where:

$HR_{z,t}$ = the heat rate of the peaking plant for Load Zone *z* and time interval *t*. The heat rate for the peaking plant shall be determined as part of the periodic review, identified in the filing required by Section 5.14.1.2.2.4.11 and remain fixed for the entire period covered by the periodic review;

$Fuel_{z,t}$ = the applicable fuel cost for the peaking plant for Load Zone *z* and time interval *t*, which shall be the lesser of the primary fuel cost and the backup fuel cost, if any, for the peaking plant for Load Zone *z*. The primary fuel and any backup fuel for the peaking plant for Load Zone *z* shall be determined as part of the periodic review, identified in the filing required by Section 5.14.1.2.2.4.11 and remain fixed for the entire period covered by the periodic review. The applicable fuel cost will be based on the applicable daily spot price for Load Zone *z* published in the specified data source determined as part of the periodic review (unless such data source is revised for the reasons described below), plus an adder to account for any applicable transportation and delivery costs and any applicable fuel taxes, which adder shall be determined as part of the periodic review, identified in the filing required by Section 5.14.1.2.2.4.11 and remain fixed for the entire period covered by the periodic review. For real-time evaluations only, the otherwise applicable fuel cost shall be increased by the applicable real-time fuel premium adder for Load Zone *z* and time interval *t*, which adder shall be determined as part of the periodic review, identified in the filing required by Section 5.14.1.2.2.4.11 and remain fixed for the entire period covered by the periodic review. The data sources used for determining the

applicable daily spot fuel prices shall be determined as part of the periodic review, identified in the filing required by Section 5.14.1.2.2.4.11 and remain fixed for the entire period covered by the periodic review, unless the specified data source is eliminated, replaced or otherwise terminated by the publisher thereof during the period covered by the periodic review. In such circumstance, the ISO shall utilize the replacement or successor data source established by the publisher, if any, or, in the absence of a replacement or successor data source, shall select as a replacement a substantially similar data source;

$VOM_{z,t}$ = variable operating and maintenance cost of the peaking plant for Load Zone *z* and time interval *t*, which cost shall be determined as part of the periodic review, identified in the filing required by Section 5.14.1.2.2.4.11 and remain fixed for the entire period covered by the periodic review;

$ASC_{z,t}$ = amortized start-up cost for the peaking plant for Load Zone *z* and time interval *t*. The model will ensure that the total value of this cost is recovered over the number of consecutive time intervals for which the model determines that the peaking plant should be committed or dispatched to produce Energy following each start of the peaking plant in the same market (Day-Ahead or real-time); provided, however, that in real-time, start-up costs must be recovered over a period of no more than two consecutive hours following the time at which the model determines that the peaking plant should be dispatched to produce Energy;

$EC_{z,t}$ = the sum of CO_2, NO_x and SO_2 emissions allowance costs for the peaking plant for Load Zone *z* and time interval *t*, which shall be calculated as follows:

$$EC_{z,t} = (CO_2 \text{ emissions rate}_{z,t} * CO_2 \text{ allowance price}_{z,t}) + (NO_x \text{ emissions rate}_{z,t} * NO_x \text{ allowance price}_{z,t}) + (SO_2 \text{ emissions rate}_{z,t} * SO_2 \text{ allowance price}_{z,t})$$

where:

The applicable emissions rates for the peaking plant for Load Zone *z* and time interval *t* shall be determined as part of the periodic review, identified in the filing required by Section 5.14.1.2.2.4.11 and remain fixed for the entire period covered by the periodic review. The applicable allowance price for each emissions type shall be the price reported by the specified data source for each emissions type determined as part of the periodic review (unless such data source is revised for the reasons described below). The data sources for allowance prices shall be determined as part of the periodic review, identified in the filing required by Section 5.14.1.2.2.4.11 and remain fixed for the entire period covered by the periodic review, unless a specified data source is eliminated, replaced or otherwise terminated by the publisher thereof during the period covered by the periodic review. In such circumstance, the ISO shall utilize the replacement or successor data source established by the publisher, if any, or, in the absence of a replacement or successor data source, shall select as a replacement a substantially similar data source; and

$RS1_{z,t}$ = the applicable charges for the ISO annual budget and the annual FERC fee assessed to Injection Billing Units for Load Zone *z* and time interval *t* in accordance with Rate Schedule 1 of the ISO OATT.

The results of the model will be used to determine an average annual net revenue value earned by each peaking plant over the period encompassed by the model. Such value will be increased by an adder to account for the estimated annual value for each Capability Year covered by the periodic review of any applicable net Ancillary Services revenue each peaking plant is eligible to receive payment for and that is not determined by the model, which adder (or methodology for determining such adder) shall be determined as part of the periodic review, identified in the filing required by Section 5.14.1.2.2.4.11 and remain fixed for the entire period

covered by the periodic review. The resulting value for each peaking plant shall be the updated net Energy and Ancillary Services revenue offset value to be used in establishing the ICAP Demand Curves for the applicable Capability Year.

5.14.1.2.2.3 Annual Updates for ICAP Demand Curve Parameters

The ISO shall use the updated peaking plant gross cost and the updated net Energy and Ancillary Services revenue offset values in determining the parameters of the ICAP Demand Curves for the applicable Capability Year.

The maximum value for each ICAP Demand Curve shall be established at 1.5 times the monthly value of the applicable updated peaking plant gross cost. Except for the ICAP Demand Curves set forth in Section 5.14.1.2.1 that apply for all months covered by the 2026-2027 Winter Capability Period, for the ICAP Demand Curves applicable prior to the 2027-2028 Capability Year, the monthly value of the applicable updated peaking plant gross cost shall, in accordance with the ISO Procedures, be determined in a manner consistent with the determination of the reference point for each ICAP Demand Curve to account for: (i) the seasonal amount of capacity available in ICAP Spot Market Auctions; and (ii) the percentage of reliability risks expected in each Capability Period. Starting with the ICAP Demand Curves applicable for the 2027-2028 Capability Year, the monthly value of the applicable updated peaking plant gross cost shall, in accordance with the ISO Procedures, be determined in a manner consistent with the determination of the reference point for each ICAP Demand Curve to account for the percentage of reliability risks expected in each Capability Period.

Except for the ICAP Demand Curves set forth in Section 5.14.1.2.1 that apply for all months covered by the 2026-2027 Winter Capability Period, for the ICAP Demand Curves applicable prior to the 2027-2028 Capability Year, the reference point for each ICAP Demand

Curve shall be determined in accordance with the ISO Procedures and, as described in Section 5.14.1.2.2 above, account for: (i) the seasonal amount of capacity available in ICAP Spot Market Auctions; and (ii) the percentage of reliability risk expected in each Capability Period. Starting with the ICAP Demand Curves applicable for the 2027-2028 Capability Year, the reference point for each ICAP Demand Curve shall be determined in accordance with the ISO Procedures and, as described in Section 5.14.1.2.2 above, account for the percentage of reliability risk expected in each Capability Period. For the ICAP Demand Curves applicable prior to the 2027-2028 Capability Year, as described in Section 5.14.1.2.2 above, the determination of the reference point for each ICAP Demand Curves shall be subject to maximum and minimum percentages of the allowable portion of the annual net revenue requirement recoverable in each Capability Period under the reference point assumed excess conditions. For ICAP Demand Curves applicable starting with the 2027-2028 Capability Year, the determination of the reference point for each ICAP Demand Curve shall be subject to maximum and minimum percentages of the allowable portion of the annual net revenue requirement recoverable in each Capability Period for conditions reflecting the prescribed level of excess for each Capability Period.

Except for the ICAP Demand Curves set forth in Section 5.14.1.2.1 that apply for all months covered by the 2026-2027 Winter Capability Period, for the ICAP Demand Curves applicable prior to the 2027-2028 Capability Year: (i) the ratio of the amount of capacity available in the ICAP Spot Market Auctions in the Winter Capability Period to the amount of capacity available in the ICAP Spot Market Auctions in the Summer Capability Period (the "winter-to-summer ratio") shall be used in calculating the reference point for each ICAP Demand Curve applicable for the Winter Capability Period; and (ii) the ratio of the amount of capacity available in the ICAP Spot Market Auctions in the Summer Capability Period to the

amount of capacity available in the ICAP Spot Market Auctions in the Winter Capability Period (the "summer-to-winter ratio") shall be used in calculating the reference point for each ICAP Demand Curve applicable for the Summer Capability Period; provided, however, that if a winter-to-summer ratio or the summer-to-winter ratio is a value less than one, the value shall be deemed to be zero for purposes of determining the applicable reference point.

Except for the ICAP Demand Curves set forth in Section 5.14.1.2.1 that apply for all months covered by the 2026-2027 Winter Capability Period, for the ICAP Demand Curves applicable prior to the 2027-2028 Capability Year, the seasonal amount of capacity available in ICAP Spot Market Auctions shall be updated annually based on the average amount of capacity available in the ICAP Spot Market Auctions for the Summer Capability Period months and Winter Capability Period months in each 12-month period (measured from September through the following August) encompassed by the same historical period utilized by the net revenue model. The values used in determining the amount of capacity available in the ICAP Spot Market Auctions shall be the available Unforced Capacity values reported by the ISO and posted on its website for the relevant months, translated to Installed Capacity values based on the applicable translation factors reported by the ISO and posted on its website for each such month. For Resources other than Special Case Resources, the values posted by the ISO shall include the following adjustments to account for ICAP market entry and exit under certain circumstances: (i) if within any of the three 12-month periods (*i.e.*, September through the following August) encompassed by the data used in calculating the amount of capacity available in ICAP Spot Market Auctions, a Resource (other than a Resource returning to participate in the ICAP market from an Inactive Reserves state) begins to qualify as eligible to participate in the ICAP market in any month encompassed by such 12-month period and remains eligible to participate in the ICAP

market for the subsequent months encompassed by that period, the ISO shall adjust the values for all months of that 12-month period to include the Resource's applicable available capacity; and (ii) if within any of the three 12-month periods (*i.e.*, September through the following August) encompassed by the data used in calculating the amount of capacity available in ICAP Spot Market Auctions, a Resource is Retired or enters a Mothball Outage or ICAP Ineligible Forced Outage state during any month encompassed by such 12-month period and remains ineligible to participate in the ICAP market for the subsequent months encompassed by that period, the ISO shall adjust the values for all months of that 12-month period to exclude the Resource's applicable available capacity.

For the ICAP Demand Curves applicable prior to the 2027-2028 Capability Year, the applicable capacity ratings for each peaking plant utilized in calculating the reference point and the point on each ICAP Demand Curve at which the price of ICAP declines to zero shall be determined as part of the periodic review and shall remain fixed for the entire period covered by the periodic review.

Starting with the ICAP Demand Curves applicable for the 2027-2028 Capability Year, the applicable capacity ratings for each peaking plant utilized in calculating the reference point shall be determined as part of the periodic review and shall remain fixed for the entire period covered by the periodic review. The zero crossing point on each ICAP Demand Curve for the Summer Capability Period shall also be determined as part of the periodic review and shall remain fixed for the entire period covered by the periodic review. The zero crossing point of each ICAP Demand Curve applicable for the Winter Capability Period of a given Capability Year shall be annually updated. In accordance with the ISO Procedures, the zero crossing point applicable to each ICAP Demand Curve applicable for the Winter Capability Period of a given

Capability Year will be calculated by multiplying the zero crossing point percentage for the applicable ICAP Demand Curve applicable for the Summer Capability Period of a given Capability Year by: (i) for the NYCA ICAP Demand Curve, the ratio of the available capacity that would be used to set the NYCA Minimum Installed Capacity Requirement for the Summer Capability Period of the upcoming Capability Year to the available capacity that would be used to set the NYCA Minimum Installed Capacity Requirement for the Winter Capability Period of the upcoming Capability Year based on the most recently NYSRC-approved assumptions matrix for the upcoming Capability Year as of November 1st of the same calendar year as the applicable November 30th deadline for posting the updated ICAP Demand Curves for the upcoming Capability Year; or (ii) for the ICAP Demand Curves for the Localities, the ratio of the available capacity that would be used to set the applicable Locational Minimum Installed Capacity Requirement for the Summer Capability Period of the upcoming Capability Year to the available capacity that would be used to set the applicable Locational Minimum Installed Capacity Requirement for the Winter Capability Period of the upcoming Capability Year based on the most recently NYSRC-approved assumptions matrix for the upcoming Capability Year as of November 1st of the same calendar year as the applicable November 30th deadline for posting the updated ICAP Demand Curves for the upcoming Capability Year. In accordance with the ISO Procedures, the prescribed level of excess for each Capability Period of a given Capability Year shall be annually updated consistent with Section 5.14.1.2.2 above. The peaking plant gross cost and net Energy and Ancillary Services revenue offset values utilized in determining the parameters of the ICAP Demand Curves for the 2025-2026 Capability Year are as follows:

	Peaking Plant Gross Cost ($ per kW-year)	Net Energy and Ancillary Services Revenue Offset ($ per kW-year)
NYCA	$127.71	$77.15

G-J	$127.58	$76.92
NYC	$222.73	$82.25
LI	$137.03	$87.42

5.14.1.2.2.4 Periodic Review Procedures

The periodic review shall be conducted in accordance with the schedule and procedures specified in the ISO Procedures. A proposed schedule will be reviewed with the stakeholders not later than May 30th of the year prior to the year of the filing specified in Section 5.14.1.2(b).11. The schedule and procedures shall provide for:

5.14.1.2.2.4.1 ISO development, with stakeholder review and comment, of a request for proposals to provide independent consulting services to determine recommended values for the factors specified above, and appropriate methodologies and inputs for such determination;

5.14.1.2.2.4.2 Selection of an independent consultant in accordance with the request for proposals;

5.14.1.2.2.4.3 Submission to the ISO and the stakeholders of a draft report from the independent consultant on the independent consultant's determination of recommended values for the factors specified above, including, as applicable, the methodologies and inputs for determining such values;

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

5.14.1.2.2.4.5 An opportunity for the Market Monitoring Unit to review and comment on the draft request for proposals, the independent consultant's report, and the ISO's proposed: (i) methodologies and inputs used for determining the ICAP Demand

Curves for the four Capability Years covered by the periodic review; and (ii) ICAP Demand Curves for the first Capability Year covered by the periodic review. The responsibilities of the Market Monitoring Unit that are addressed in this section of the Services Tariff are also addressed in Section 30.4.6.3.1 of Attachment O;

5.14.1.2.2.4.6 Issuance by the independent consultant of a final report;

5.14.1.2.2.4.7 Issuance of a draft of the ISO's recommended: (i) methodologies and inputs used for determining the ICAP Demand Curves for the four Capability Years covered by the periodic review; and (ii) ICAP Demand Curves for the first Capability Year covered by the periodic review, for stakeholder review and comment;

5.14.1.2.2.4.8 Issuance of the ISO's proposed: (i) methodologies and inputs used for determining the ICAP Demand Curves for the four Capability Years covered by the periodic review; and (ii) ICAP Demand Curves for the first Capability Year covered by the periodic review, taking into account the report of the independent consultant, the recommendations of the Market Monitoring Unit, and the views of the stakeholders together with the rationale for accepting or rejecting any such inputs;

5.14.1.2.2.4.9 Submission of stakeholder requests for the ISO Board of Directors to review and adjust the ISO's proposed: (i) methodologies and inputs used for determining the ICAP Demand Curves for the four Capability Years covered by the periodic review; and (ii) ICAP Demand Curves for the first Capability Year covered by the periodic review;

5.14.1.2.2.4.10 Presentations to the ISO Board of Directors of stakeholder views on the ISO's proposed: (i) methodologies and inputs used for determining the ICAP Demand Curves for the four Capability Years covered by the periodic review; and (ii) ICAP Demand Curves for the first Capability Year covered by the periodic review; and

5.14.1.2.2.4.11 Filing with the Commission of: (i) a description of the methodologies and inputs used for determining the ICAP Demand Curves for the four Capability Years covered by the periodic review; and (ii) the ICAP Demand Curves for the first Capability Year covered by the periodic review, as approved by the ISO Board of Directors incorporating the results of the periodic review. Such filing will be made not later than November 30th of the year prior to the year that includes the beginning of the first Capability Year covered by the periodic review. The filing will also specify the inflation rate that would have been used to calculate the general component of the escalation factor as if the escalation factor were applicable to the first Capability Year covered by the periodic review. Such inflation rate shall be equal to the twelve month percentage change in the applicable index for the general component, as determined in accordance with Section 5.14.1.2.2.1 utilizing the applicable values of the index as of October 1st in the same calendar year as the November 30th filing deadline specified above. For each of the subsequent three Capability Years encompassed by the periodic review, the value of this inflation rate shall be the twelve month percentage change in the applicable index for the general component of the escalation factor, as determined pursuant to Section 5.14.1.2.2.1, utilizing the most recently

available finalized values established by the publisher for the index as of October 1st in the same calendar year as the applicable November 30th deadline for posting the updated ICAP Demand Curves for the Capability Year at issue and the applicable values for the corresponding period from the calendar year immediately preceding thereto.

The ICAP Demand Curves will be translated into Unforced Capacity terms in accordance with the ISO Procedures. Beginning with the 2024-2025 Capability Year, the aforementioned translation shall utilize the applicable derating factor of the peaking plant used to establish each ICAP Demand Curve, as determined during the periodic review conducted pursuant to Section 5.14.1.2.2. Nothing in this Tariff shall be construed to limit the ability of the ISO or its Market Participants to propose and adopt alternative provisions to this Tariff through established governance procedures.

5.14.1.3 Supplemental Supply Fee

Any LSE that has not met its share of the NYCA Minimum Installed Capacity Requirement or its share of the Locational Minimum Installed Capacity Requirement after the completion of an ICAP Spot Market Auction, shall be assessed a supplemental supply fee equal to the applicable Market-Clearing Price of Unforced Capacity determined in the ICAP Spot Market Auction multiplied by the number of MWs the LSE needs to meet its share of the NYCA Minimum Installed Capacity Requirement or its share of the Locational Minimum Installed Capacity Requirement.

The ISO will attempt to use these supplemental supply fees to procure Unforced Capacity at a price less than or equal to the applicable Market-Clearing Price of Unforced Capacity determined in the ICAP Spot Market Auction from Installed Capacity Suppliers that are capable

of supplying Unforced Capacity including: (1) Installed Capacity Suppliers that were not qualified to supply Capacity prior to the ICAP Spot Market Auction; (2) Installed Capacity Suppliers that offered Unforced Capacity at levels above the ICAP Spot Market Auction Market-Clearing Price; and (3) Installed Capacity suppliers that did not offer Unforced Capacity in the ICAP Spot Market Auction. In the event that different Installed Capacity Suppliers offer the same price, the ISO will give preference to Installed Capacity Suppliers that were not qualified to supply capacity prior to the ICAP Spot Market Auction.

Offers from Installed Capacity Suppliers are subject to review pursuant to the Market Monitoring Plan that is set forth in Attachment O to the Services Tariff, and the Market Mitigation Measures that are set forth in Attachment H to the Services Tariff. Installed Capacity Suppliers selected by the ISO to provide capacity after the ICAP Spot Market Auction will be paid a negotiated price, subject to the standards, procedures and remedies in the Market Mitigation Measures.

The ISO will not pay an Installed Capacity Supplier more than the applicable Market-Clearing Price of Unforced Capacity determined in the ICAP Spot Market Auction per MW of Unforced Capacity, or, in the case of In-City generation that is subject to Capacity market mitigation measures, the annual mitigated price cap per MW of Unforced Capacity, whichever is less, pro-rated to reflect the portion of the Obligation Procurement Period for which the Installed Capacity Supplier provides Unforced Capacity. Any remaining monies collected by the ISO pursuant to this section will be applied in accordance with Section 5.14.3 of the Services Tariff.

5.14.2 Installed Capacity Supplier Shortfalls and Deficiency Charges

5.14.2.1 General Provisions

In the event that an Installed Capacity Supplier sells in the Capability Period Auctions, in the Monthly Auctions, or through Bilateral Transactions more Unforced Capacity than it is qualified to sell in any specific month due to a de-rating or other cause, the Installed Capacity Supplier shall be deemed to have a shortfall for that month. To cover this shortfall, the Installed Capacity Supplier shall purchase sufficient Unforced Capacity in the relevant Monthly Auction or through Bilateral Transactions, and certify to the ISO consistent with the ISO Procedures that it has covered such shortfall. If the Installed Capacity Supplier does not cover such shortfall or if it does not certify to the ISO in a timely manner, the ISO shall, to the extent the ISO is aware of the shortfall, prospectively purchase Unforced Capacity on behalf of that Installed Capacity Supplier in the appropriate ICAP Spot Market Auction or through post ICAP Spot Market Auction Unforced Capacity purchases to cover the shortfall.

The ISO shall submit a Bid, calculated pursuant to Section 5.14.1 of this Tariff, in the appropriate ICAP Spot Market Auction on behalf of an Installed Capacity Supplier deemed to have a shortfall as if the Installed Capacity Supplier were an LSE. Such Installed Capacity Supplier shall be required to pay to the ISO the applicable Market-Clearing Price of Unforced Capacity established in that ICAP Spot Market Auction. Immediately following the ICAP Spot Market Auction, the ISO may suspend the Installed Capacity Supplier's privileges to sell or purchase Unforced Capacity in ISO-administered Installed Capacity auctions or to submit Bilateral Transactions to the NYISO. Once the Installed Capacity Supplier pays for or secures the payment obligation that it incurred in the ICAP Spot Market Auction, the ISO shall reinstate the Installed Capacity Supplier's privileges to participate in the ICAP markets.

In the event that the ICAP Spot Market Auction clears below the NYCA Minimum Installed Capacity Requirement or the Locational Minimum Installed Capacity Requirement, whichever is applicable to the Installed Capacity Supplier, and the Installed Capacity Supplier is deemed to have a shortfall, the Installed Capacity Supplier shall be assessed the applicable deficiency charge equal to the applicable Market-Clearing Price of Unforced Capacity determined using the applicable ICAP Demand Curve for that ICAP Spot Market Auction, times the amount of its shortfall.

If an Installed Capacity Supplier is found, at any point during a Capability Period, to have had a shortfall for that Capability Period, *e.g.,* when the amount of Unforced Capacity that it supplies is found to be less than the amount it was committed to supply, the Installed Capacity Supplier shall be retrospectively liable to pay the ISO the monthly deficiency charge equal to one and one-half times the applicable Market-Clearing Price of Unforced Capacity determined using the applicable ICAP Demand Curve for that ICAP Spot Market Auction times the amount of its shortfall for each month the Installed Capacity Supplier is deemed to have a shortfall. If the Installed Capacity Supplier is a RIP or an Aggregator, it may experience a shortfall when, among other reasons, it sells ineligible or unavailable capacity MW associated with a properly or improperly enrolled SCR or Distributed Energy Resource.

The ISO, when evaluating whether an Installed Capacity Supplier has a shortfall, may use either Unforced Capacity data or Installed Capacity data; provided, however, that the ISO shall convert any shortfall MWs based on Installed Capacity data to its Unforced Capacity equivalent prior to calculating the amount of any deficiency charge. All shortfalls shall be measured in MWs in increments of 0.1 MW.

Any remaining monies collected by the ISO pursuant to Section 5.14.1 and 5.14.2 will be applied as specified in Section 5.14.3.

5.14.2.2 Additional Provisions Applicable to External Installed Capacity Suppliers

In addition to the general provisions set forth in Section 5.14.2.1 above that are applicable to External Installed Capacity Suppliers as Installed Capacity Suppliers, the following provisions shall also apply to External Installed Capacity Suppliers.

In the event that an External Installed Capacity Supplier fails to deliver to the NYCA the Energy associated with the Unforced Capacity it committed to the NYCA due to a failure to obtain appropriate transmission service or rights, the External Installed Capacity Supplier shall be deemed to have a shortfall from the last time the External Installed Capacity Supplier "demonstrated" delivery of its Installed Capacity Equivalent ("ICE"), or any part thereof, until it next delivers its ICE or the end of the term for which it certified the applicable block of Unforced Capacity, whichever occurs first, subject to the limitation that any prior lack of demonstrated delivery will not precede the beginning of the period for which the Unforced Capacity was certified. An External Installed Capacity Supplier deemed to have a shortfall shall be required to pay to the ISO a deficiency charge equal to one and one-half times the applicable Market-Clearing Price of Unforced Capacity determined in the ICAP Spot Market Auction for the applicable month, prorated for the number of hours in the month that External Installed Capacity Supplier is deemed to have a shortfall (i.e., (((deficiency charge ÷ 12 months) ÷ total number of hours in month when shortfall occurred) * number of hours the shortfall lasted) * number of MWs of shortfall).

5.14.2.3 Additional Provisions Applicable to RIPs

In addition to the general provisions set forth in Section 5.14.2.1 above that are applicable to RIPs as Installed Capacity Suppliers, this Section 5.14.2.3 establishes the following four specific shortfalls applicable to RIPs: 1. shortfall for Provisional ACL; 2. shortfall for Incremental ACL; 3. shortfall for SCR Change of Status; and 4. shortfall for RIP portfolio performance. The deficiency charge for any such shortfall shall be equal to the Unforced Capacity equivalent of the shortfall multiplied by one and one-half times the applicable Market-Clearing Price of Unforced Capacity determined using the applicable ICAP Demand Curve for the ICAP Spot Market Auction for each month the RIP is deemed to have a shortfall.

There are three distinct measures of shortfall that are applicable to a RIP, described in this Section 15.4.2.3, where individual SCRs that have been enrolled with a Provisional ACL or an Incremental ACL, or that experience a SCR Change of Status may result in a shortfall. When a RIP is subject to multiple deficiency charges for the same SCR for the same Capability Period, the ISO shall assess to the RIP only the greatest deficiency charge related to such SCR. In addition, if the shortfall results in a reduction in the performance of a SCR, the ISO may recover from the RIP any energy payments for which the SCR was ineligible to receive.

5.14.2.3.1 Shortfall for Provisional ACL

Prior to the Summer 2014 Capability Period if the Installed Capacity Supplier is a Responsible Interface Party, after each Special Case Resource with a Provisional Average Coincident Load has its Average Coincident Load determined for the Capability Period in which it had a Provisional Average Coincident Load (such determination in accordance with ISO Procedures and without regard to whether the resource was registered to the same Responsible Interface Party at the time of the ACL determination), the ISO shall determine if there is a

shortfall due to the Provisional Average Coincident Load being higher than the Average Coincident Load. This shortfall will be equal to the value, if positive, of (x) the sum of (i) the amount of UCAP a Responsible Interface Party sold in an Monthly or an ICAP Spot Market Auction or certified Bilateral Transactions for a Special Case Resource and (ii) the Special Case Resource's actual metered demand for the month in accordance with ISO Procedures, minus (y) the Special Case Resource's Average Coincident Load. If the ISO does not receive data to determine the Average Coincident Load in accordance with ISO Procedures, for each Capability Period a Special Case Resource had a Provisional Average Coincident Load, for purposes of determining the shortfall, the Average Coincident Load shall equal zero.

Beginning with the Summer of 2014 Capability Period if the Installed Capacity Supplier is a Responsible Interface Party, after each SCR with a Provisional ACL has its Verified ACL determined for the Capability Period in which it had a Provisional ACL (such determination in accordance with Section 5.12.11.1 and ISO Procedures) the ISO shall determine if there is a shortfall due to the Provisional ACL being greater than the Verified ACL. This shortfall shall be equal to the value, if positive, of (x) the Provisional ACL of the SCR, minus (y) the Verified ACL of the SCR. The shortfall calculated for the SCR for a month shall not exceed the amount of Installed Capacity associated with the SCR that was sold for that month. If the ISO does not receive data to determine the SCR's Verified ACL for the Capability Period for which the SCR was enrolled with a Provisional ACL the Verified ACL shall equal zero.

5.14.2.3.2 Shortfall for Incremental ACL

If the Installed Capacity Supplier is a RIP that reported an Incremental ACL, the ISO shall determine there is a shortfall when the Net ACL is greater than the Verified ACL. This shortfall shall be equal to the value, if positive, of (x) the enrolled Net ACL of the SCR, minus

(y) the Verified ACL of the SCR for each month in which the RIP sold the SCR's Installed Capacity. The shortfall calculated for the SCR for a month shall not exceed the amount of Installed Capacity associated with the SCR that was sold for that month. If the ISO does not receive data to determine the Verified ACL for each month within the Capability Period that the SCR was enrolled with an Incremental ACL, the Monthly ACL for each unreported month shall equal zero (0) and be used in the calculation of the Verified ACL in accordance with Section 5.12.11.1.5.

5.14.2.3.3 Shortfall for SCR Change of Status

If the Installed Capacity Supplier is a RIP, and a SCR Change of Status occurs, the ISO shall determine if a shortfall exists, based on the RIP's reporting of the SCR Change of Status.

When a SCR Change of Status is reported by the RIP in advance and no Installed Capacity associated with the SCR has been sold, a shortfall has not occurred. If the SCR Change of Status is reported by the RIP, but the Installed Capacity associated with the SCR has already been sold for one or more months a shortfall exists for these months, the shortfall shall be equal to the reduction to the ACL reported in the SCR Change of Status, but shall not exceed the amount of Installed Capacity sold for each month.

When the RIP fails to report the SCR Change of Status during the Capability Period, for each month in which the SCR's Installed Capacity was sold and the SCR Change of Status was in effect, the ISO shall determine the shortfall MW using the maximum one hour metered Load for the month. The shortfall amount for each month in which the SCR Change of Status was in effect shall equal the value of SCR ACL minus the maximum one hour metered Load for the month, but shall not exceed the SCR's Installed Capacity sold for the month.

5.14.2.3.4 Shortfall for RIP Portfolio Performance

In addition to the shortfall evaluations based on individual SCRs, a RIP is subject to a shortfall evaluation, by Load Zone, for its entire SCR portfolio. In this evaluation the shortfall shall be determined for each Load Zone separately. A shortfall will occur if the total of the amount of UCAP sold by the RIP for a month in a Capability Period Auction or a Monthly Auction and certified prior to that month's ICAP Spot Market Auction, the UCAP sold in that month's ICAP Spot Market Auction, and the UCAP sold as a Bilateral Transaction and certified prior to that month's ICAP Spot Market Auction is greater than the greatest quantity MW reduction achieved during a single hour in a test or event called by the ISO in the Capability Period as confirmed by data by the ISO in accordance with ISO Procedures (or the value of zero if data is not received by the ISO in accordance with such procedures).

5.14.3 Application of Installed Capacity Supplier Deficiency Charges

Any remaining monies collected by the ISO through supplemental supply fees or Installed Capacity Supplier deficiency charges pursuant to Section 5.14.1 but not used to procure Unforced Capacity on behalf of LSEs or Installed Capacity suppliers deemed to have a shortfall shall be applied as provided in this Section 5.14.3.

5.14.3.1 General Application of Deficiency Charges

Except as provided in Section 5.14.3.2, remaining monies will be applied to reduce the Rate Schedule 1 charge in the following month.

5.14.3.2 Installed Capacity Rebates

(i) New York City

If an Unforced Capacity shortfall exists during any month, the ISO shall rebate any remaining unspent deficiency charges or supplemental supply fees collected for that month for the New York City Locality allocated among all LSEs in that Locality in proportion to their share of the applicable Locational Minimum Installed Capacity Requirement. Rebates shall include interest accrued between the time payments were collected and the time that rebates are paid.

(ii) Long Island

If an Unforced Capacity shortfall exists during any month, the ISO shall rebate any remaining unspent deficiency charges or supplemental supply fees collected for that month for the Long Island Locality, allocated among all LSEs in that Locality in proportion to their share of the applicable Locational Minimum Installed Capacity Requirement. Rebates shall include interest accrued between the time payments were collected and the time that rebates are paid.

(iii) G-J

If an Unforced Capacity shortfall exists during any month, the ISO shall rebate any remaining unspent deficiency charges or supplemental supply fees collected for that month for the G-J Locality, allocated among all LSEs in that Locality in proportion to their share of the applicable Locational Minimum Installed Capacity Requirement. Rebates shall include interest accrued between the time payments were collected and the time that rebates are paid.

(iv) Rest of State

If an Unforced Capacity shortfall exists during any month, the ISO shall rebate any remaining unspent deficiency charges or supplemental supply fees collected for that month for the Rest of State requirements, allocated among all LSEs in each of the Localities and in Rest of State, in proportion to each LSE's share of the NYCA Minimum Installed Capacity Requirement less that LSE's Locational Minimum Installed Capacity Requirement. Rebates shall include interests accrued between the time payments were collected and the time that rebates are paid.

5.15 Payment and Allocation of Installed Capacity Auction Rebates

The ISO shall rebate to all LSEs with Locational Minimum Installed Capacity Requirements in the New York City Locality, except NYPA, any Excess Amount that remains after the completion of an auction. Such rebates shall be allocated among all New York City LSEs, except NYPA, in proportion to their share of the Locational New York City Installed Capacity Requirement, regardless of whether they actually took part in the Capability Period Auctions or Monthly Auctions. The ISO shall allocate such rebates among In-City LSEs except NYPA on a monthly basis. Rebates shall include interest accrued between the time they were collected and the time that they are paid.

5.16 New Capacity Zone Study and Procedures

Capitalized terms used in this Section 5.16 and not defined in this Services Tariff shall have the meaning set forth in the Open Access Transmission Tariff.

The ISO shall conduct the New Capacity Zone study in accordance with this Section ("NCZ Study") and provide a written report of the results to stakeholders on or before January 15 in each ICAP Demand Curve Reset Filing Year.

5.16.1 NCZ Study Methodology.

5.16.1.1 The NCZ Study, developed in accordance with ISO Procedures, will test, under summer peak system conditions, using the following assumptions and methodology:

5.16.1.1.1 The following assumptions will be applied: (i) transmission facilities (other than existing Class Year Transmission Projects or existing Cluster Study Transmission Projects) identified as existing in the ISO's Load and Capacity Data report most recently published prior to the NCZ Study Start Date; (ii) all firm plans for changes to transmission facilities by Transmission Owners in the ISO's Load and Capacity Data report most recently published prior to the NCZ Study Start Date scheduled to be in-service prior to the NCZ Study Capability Period; (iii) planned generation projects, Class Year Transmission Project, or Cluster Study Transmission Projects that have accepted either (a) Deliverable MW or (b) a System Deliverability Upgrade cost allocation and provided cash or posted required security pursuant to, as applicable, Attachment S or Attachment HH to the ISO OATT, which for (a) and (b) is from a Final Decision Round of a Class Year Study, a Final Decision Period of a Cluster Study, or an Additional SDU

Study Decision Period that occurs prior to the NCZ Study Start Date (subject to Section 5.16.1.1.2); (iv) System Upgrade Facilities and System Deliverability Upgrades associated with planned projects identified in (iii) above, except that System Deliverability Upgrades where construction of the System Deliverability Upgrade has been deferred pursuant to Sections 25.7.12.2 and 25.7.12.3 of Attachment S or Sections 40.13.12.2 and 40.13.12.3 of Attachment HH to the ISO OATT will only be included if construction of the System Deliverability Upgrades has been triggered under Section 25.7.12.3 of Attachment S or Section 40.13.12.3 of Attachment HH to the ISO OATT; (v) all transmission retirements and derates identified in the ISO's Load and Capacity Data report most recently published prior to the NCZ Study Start Date and scheduled to occur prior to the NCZ Study Capability Period; (vi) all existing Generators with CRIS identified in, and all projects with Unforced Capacity Deliverability Rights on the date of, the ISO's Load and Capacity Data report most recently published prior to the NCZ Study Start Date; and all CRIS rights from resources considered "CRIS-inactive" as defined in Section 40.18.2.1 of Attachment HH to the ISO OATT unless the ability to transfer those rights has expired without completing a transfer as permitted under Section 40.18.3 or 40.18.4 of Attachment HH to the ISO OATT as of the NCZ Study Start Date; and (vii) any transfer of CRIS rights pursuant Attachment S or HH of the ISO OATT not identified in the Load and Capacity Data report most recently published prior to the NCZ Study Start Date but is completed and the transferee is operational prior to the NCZ Study Start Date.

5.16.1.1.2 Planned generation, Class Year Transmission Projects, and Cluster Study Transmission Projects identified pursuant to Section 5.16.1.1.1 will be excluded and not recognized in the NCZ Study if (a) the Commission has accepted the cancellation or termination of a rate schedule consisting of an interconnection agreement (absent the filing of another interconnection agreement for the project), or (b) for projects that either do not have an executed interconnection agreement or have an executed interconnection agreement that is (i) not required to be filed with the Commission or (ii) is required to be filed but has not yet been filed, the ISO receives written notice from the project that it is withdrawing from the interconnection queue and/or a Notice of Termination under the interconnection agreement.

5.16.1.1.3 The Load forecast used will be the NCZ Study Capability Period peak demand forecast contained in the ISO's Load and Capacity Data report most recently published prior to the NCZ Study Start Date.

5.16.1.1.4 The base case conditioning steps contained in Sections 25.7.8.2.1.3 (excluding and not recognizing MW of CRIS requested by Interconnection Customers other than CRIS identified in Section 5.16.1.1.1 (iii)), 40.13.8.2.1.4, 40.13.8.2.1.5, 40.13.8.2.1.10, and 40.13.8.2.1.11 of Attachment HH to the ISO OATT will be applied to the above inputs and assumptions.

5.16.1.1.5 The ISO will perform the NCZ Study by applying to the above inputs and assumptions the methodology contained in Sections 40.13.8.2.1.6, 40.13.8.2.1.7, 40.13.8.2.1.8, 40.13.8.2.1.9, 40.13.8.2.1.12, and 40.13.8.2.1.13 of Attachment HH to the ISO OATT to Highways. Deliverability will be determined through a shift

from generation to generation within each Capacity Region that contains Highways. Each such Capacity Region will be tested on an individual basis.

5.16.1.2 On or before October 1 of the year prior to an ICAP Demand Curve Reset Filing Year, the ISO will review the inputs and assumptions for the NCZ Study with stakeholders and provide an opportunity for stakeholders to comment.

5.16.1.3 The ISO shall provide an opportunity for the Market Monitoring Unit to review and comment on the NCZ Study consistent with Services Tariff Attachment O Section 30.4.6.3.2.

5.16.2 New Capacity Zone Boundary

The ISO shall identify the boundary of a New Capacity Zone if there is a constrained Highway interface into one or more Load Zones. The boundary of the New Capacity Zone may encompass a single constrained Load Zone or group of Load Zones including one or more constrained Load Zones on the constrained side of the Highway. In determining the New Capacity Zone boundary, the ISO shall consider the extent to which incremental Capacity in individual constrained Load Zones could impact the reliability and security of constrained Load Zones, taking into account interface capability between constrained Load Zones.

5.16.3 Indicative NCZ Locational Minimum Installed Capacity Requirement

For each Load Zone or groups of Load Zones identified in the NCZ Study as having a constrained Highway Interface, on or before March 1 of each ICAP Demand Curve Reset Filing Year, the ISO shall determine Indicative NCZ Locational Minimum Installed Capacity Requirements for each Capability Period. The ISO shall provide an opportunity to stakeholders to review and comment on the Indicative NCZ Locational Minimum Installed Capacity

Requirements. This Indicative NCZ Locational Minimum Installed Capacity Requirements will be used solely for establishing revised ICAP Demand Curves in accordance with 5.14.1.2.

5.16.4 NCZ Report

On or before March 31 of an ICAP Demand Curve Reset Filing Year,

(a) If the NCZ Study identifies a constrained Highway Interface, the ISO shall file for Commission review proposed tariff revisions necessary to establish and recognize the New Capacity Zone or Zones, and shall include in the filing a report of the results of the NCZ Study. If the ISO proposes that a New Capacity Zone that is comprised of a group of Load Zones instead of a single Load Zone, the ISO shall include in the filing the basis for its determination, consistent with Section 5.16.2.

(b) If the NCZ Study does not identify a constrained Highway interface, the ISO shall file with the Commission the ISO's determination that the NCZ Study did not indicate that any New Capacity Zone is required pursuant to this process, along with a report of the results of the NCZ Study.

The ISO shall provide an opportunity for the Market Monitoring Unit to review and comment on the NCZ Study and any proposed tariff revisions, consistent with Services Tariff Attachment O Section 30.4.6.3.2.

5.17 Expedited Dispute Resolution Procedures

5.17.1 Five-Day Consultation Period

Parties to a dispute involving a matter that is subject to the procedures of this section must immediately confer and attempt to resolve the dispute on an informal basis. If the parties are unable to resolve the dispute within five (5) calendar days by mutual agreement, the dispute shall be immediately submitted to the ISO's Dispute Resolution Administrator ("DRA").

5.17.2 Written Submissions

Immediately upon conclusion of the five-day consultation period, the party requesting the dispute resolution shall submit to the DRA and all other parties to the dispute, a concise written statement specifying that expedited dispute resolution under this section is requested and describing the nature of the dispute, the issues to be resolved and the specific award requested. The party opposing the requested relief shall then have five (5) calendar days to submit to the DRA and the party requesting the dispute resolution, a concise written response which shall include a proposed disposition of the dispute.

5.17.3 Appointment of the Arbitrator

The DRA shall keep at all times a list of ten (10) qualified arbitrators for matters which may be subject to the procedures of this section. Within five (5) calendar days of receipt of a request for dispute resolution under this section, the DRA shall appoint one arbitrator from that list to preside over the dispute. The arbitrator shall be selected by the DRA by randomly drawing names from the list until an available arbitrator is found. If none of the arbitrators on the list is available, the DRA shall appoint a qualified arbitrator to preside over the dispute. No person shall be eligible to act as an arbitrator who is a past or present officer, employee of, or

consultant to any of the disputing parties, or of an entity related to or affiliated with any of the disputing parties, or is otherwise interested in the matter to be arbitrated except upon the express written consent of the parties. Any individual appointed as an arbitrator shall make known to the disputing parties any such disqualifying relationship or interest and a new arbitrator shall be appointed by the DRA, unless express written consent is provided by each party.

5.17.4 Arbitration Proceeding

There shall be no right to discovery between the parties, including, but not limited to, depositions, interrogatories or other information requests. The arbitrator may request, and the parties shall produce, any information in addition to the written statements that is deemed by the arbitrator to be relevant to the issues presented. The arbitrator shall resolve the arbitration matter solely on the basis of the written statements and evidence submitted by the parties unless, in the sole discretion of the arbitrator, a hearing is deemed necessary. Any such hearing shall be limited to one (1) day and conducted in accordance with the procedures determined by the arbitrator. Absent agreement to the contrary by all parties to the dispute, no person or entity shall be permitted to intervene. Except as otherwise set forth in this section, the arbitrator will follow the Commercial Arbitration Rules of the American Arbitration Association and the expedited procedures contained therein.

5.17.5 Arbitration Award

Within fifteen (15) calendar days of the appointment of the arbitrator, the arbitrator shall select as an arbitration award the award proposed by one of the parties in their written submission (except that, in disputes concerning the development of regional Load growth factors pursuant to Section 5.10 of this Tariff, the arbitration award shall be either the forecast developed by the Transmission Owner or by the ISO) and shall render a concise written decision

including findings of fact and the basis for the decision. All costs associated with the time, expenses, and other charges of the arbitrator shall be borne by the unsuccessful party. Each party shall bear its own costs, including attorney and expert fees, if any. No award shall be deemed to be precedential in any other arbitration related to a different dispute.

5.17.6 Limited Appeal

The decision of the arbitrator shall be final and binding upon the parties, except that, within one year of the arbitration decision, a party may request that any federal, state regulatory or judicial authority (in the State of New York) having jurisdiction take such action as may be appropriate with respect to any arbitration decision that is based on fraudulent conduct or demonstrable bias of the arbitrator.

5.18 Generator Outages and Generator Obligations While in These Outages

This Section 5.18 shall apply to a Generator in any outage state that started on or after May 1, 2015, except for a Generator participating in the ISO Markets as part of an Aggregation. Section 5.18 shall apply to a Generator that is in an outage state at the time that it joins an Aggregation until that Generator returns to operation.

A Market Participant with a Generator in the NYCA that is in any outage state, which is not part of an Aggregation, shall report its status to the ISO pursuant to ISO Procedures.

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

5.18.1 Forced Outages and Commenced Repair Determinations

5.18.1.1 A Market Participant with a Generator in a Forced Outage shall keep the ISO informed as to progress of its Generator's repairs pursuant to ISO

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

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

that would be included in a Credible Repair Plan pursuant to Section 5.18.1.5 of this Services Tariff.

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

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

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

the Generator and which forced outage occurred under the same, or reasonably similar, circumstances as the Generator's. A Credible Repair Plan for a Generator in a Mothball Outage is a Repair Plan that would also be expected from a supplier pursuing a repair to its generating facility which repair is reasonably the same as or comparable to the repair being pursued by the Generator.

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

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

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

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

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

5.18.2 ICAP Ineligible Forced Outage

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

A Generator in an ICAP Ineligible Forced Outage as a result of the

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

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

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

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

5.18.2.3 ICAP Ineligible Force Outage Expiration

5.18.2.3.1 Except as provided in Section 5.18.2.3.2, a Generator's ICAP Ineligible Forced Outage shall expire if: i) its CRIS rights have expired; or ii) it did not have CRIS rights and has been in the ICAP Ineligible Forced Outage for 36 consecutive months. A Generator shall be Retired if its ICAP Ineligible Forced Outage expires.

5.18.2.3.2 If a Market Participant with a Generator in an ICAP Ineligible Forced Outage has Commenced Repair prior to when the ICAP Ineligible Forced Outage would expire pursuant to Section 5.18.2.3.1 and has provided a reasonable return date as that term is described in Section 5.18.1.2 of this Services Tariff that occurs after such expiration date, then the outage and the Generator's CRIS rights will be tolled until, and the ICAP Ineligible Forced Outage will expire on, the earlier of: i) 120 days from when the outage would have expired under Section 5.18.2.3.1; or ii) an ISO determination that the Market Participant has ceased or unreasonably delayed the repair of its Generator. The ISO will determine if a Market Participant has unreasonably delayed the repair of its Generator if such delay would not have been included in a Credible Repair Plan from a supplier experiencing the situation which caused the Market Participant to delay the repair of its Generator. The tolling of CRIS rights occurs under this Section 5.18.2.3.2 notwithstanding the three year period in which CRIS-inactive facilities may maintain CRIS rights pursuant to Section 40.18.2.1 of Attachment HH to the OATT; provided, however, the expiration period for transfers of CRIS rights provided in Section 40.18.2.1 of Attachment HH to the OATT shall not be tolled.

A Market Participant seeking to toll its outage and CRIS rights pursuant to this Section 5.18.2.3.2 must submit a Repair Plan no later than 60 days prior to when the ICAP Ineligible Forced Outage would expire under Section 5.18.2.3.1.

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

5.18.3 Mothball Outage

5.18.3.1 Prior to entering a Mothball Outage, the Generator must satisfy the prior notice requirement contained in Section 38.3.1 of Attachment FF to the ISO OATT, among other applicable requirements. A Generator in a Mothball Outage is not eligible to participate in the Installed Capacity market and shall

automatically cease to qualify to participate in the Installed Capacity market beginning with the date the Generator begins its Mothball Outage. The Generator shall no longer be ineligible to participate in the Installed Capacity market, by virtue of its Mothball Outage, as of the first day the Generator returns to operation and offers its Energy into the Day-Ahead Market without declaring an outage. The month for which the Generator will first be eligible to participate in the Installed Capacity market will be based on the date the Generator returns to operation and offers its Energy into the Day-Ahead Market without declaring an outage and ISO Procedures.

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

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

the applicable Transmission Owner(s).

5.18.3.3 Mothball Outage Expiration

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

5.18.3.3.2 If a Market Participant with a Generator in a Mothball Outage has Commenced Repair prior to when the Mothball Outage would expire pursuant to Section 5.18.3.3.1 and has provided a reasonable return date as that term is described in Section 5.18.1.2 of this Services Tariff that occurs after such expiration date, then the outage and the Generator's CRIS rights will be tolled until, and the Mothball Outage will expire on, the earlier of: i) 120 days from when the outage would have expired under Section 5.18.3.3.1; or ii) an ISO determination that the Market Participant has ceased or unreasonably delayed the repair of its Generator. The ISO will determine if a Market Participant has unreasonably delayed the repair of its Generator if such delay would not have been included in a Credible Repair Plan from a supplier experiencing the situation which caused the Market Participant to delay the repair of its Generator. The tolling of CRIS rights occurs under this Section 5.18.3.3.2 notwithstanding the three year period in which CRIS-inactive facilities may maintain CRIS rights pursuant to Section 40.18.2.1of Attachment HH to the OATT; provided, however, the expiration period for transfers of CRIS rights provided in Section 40.18.2.1 of Attachment HH to the OATT shall not be tolled. A Market Participant seeking to

toll Its outage and CRIS rights pursuant to this Section 5.18.3.3.2 must submit a Repair Plan no later than 60 days prior to when the Mothball Outage would expire under Section 5.18.3.3.1.

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

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

5.18.4.1 Following: i) notification to a Market Participant that the return to service of its Generator in a Mothball Outage or an ICAP Ineligible Forced Outage for a specified minimum time period has been identified as a Short-Term Reliability Process Solution, a Gap Solution, or to resolve a reliability issue on a non-New York State Bulk Power Transmission Facility arising during the Generator's outage; and ii) an order establishing compensation for such return from the

Federal Energy Regulatory Commission ("Compensation Order"), the Market Participant shall timely return the Generator to service, as the term "timely return" is defined in Section 5.18.4.2 of this Services Tariff.

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

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

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

otherwise agreed.

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

5.18.5 Temporary Use of Interconnection Point to Resolve a Reliability Issue

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

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

Outage, shall be permitted to reconnect at no cost.

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

If the Generator returning to service pursuant to this Section 5.18.5.2 of the Services Tariff is available to return but the Transmission Owner is unable to reconnect the Generator before its outage expires, the outage expiration, and expiration of its CRIS rights, where applicable, will be tolled until the date the Transmission Owner reconnects the Generator notwithstanding the three year period in which CRIS-inactive facilities may maintain CRIS rights pursuant to Section 40.18.2.1 of Attachment HH to the OATT; provided, however, the expiration period for transfers of CRIS rights provided in Section 40.18.2.1 of Attachment HH to the OATT shall not be tolled.

5.18.6 Retired and Termination of Existing Interconnection Agreements

The classification of a Generator with an interconnection agreement other than a Small Generator Interconnection Agreement (SGIA), Standard Large Generator Interconnection Agreement (LGIA), or Standard Interconnection Agreement (IA) as Retired may be grounds for

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

The impact on a Generator with a LGIA, SGIA, or IA that has been classified as Retired is described in Section 40 of the ISO OATT.

6 Confidentiality

6.1 Access to Confidential Information

The ISO may request, and the Customer shall provide, Confidential Information consistent with the disclosure requirements set forth in the ISO Services Tariff (as provided for below). The ISO shall use reasonable procedures to prevent the disclosure of Confidential Information and shall not publish, disclose or otherwise divulge Confidential Information to any person or entity without the prior written consent of the party supplying such Confidential Information, except as provided for under the ISO Market Monitoring Plan and/or ISO Code of Conduct. The provisions of this section shall not apply to any Confidential Information: (i) which was in the public domain at the time of disclosure hereunder; (ii) which thereafter passes into the public domain by acts other than the acts of the ISO; or (iii) that the ISO is required to make publicly available by the Commission, the PSC or other legal process, or for reliability purposes pursuant to Good Utility Practice.

A Customer may request that the ISO keep confidential from another entity Confidential Information that the other entity does not require to perform its obligations and duties hereunder. The Customer must state in writing that the information is to be treated as Confidential Information and the reasons for treating it as Confidential Information, otherwise information will be treated as non-Confidential Information.

6.2 Use of Confidential Information

The ISO shall use Confidential Information for the exclusive purpose of performing its obligations hereunder and under any Service Agreement. The ISO will treat this information in conformity with the standards of conduct contained in Part 37 of the Commission's Regulations and the Code of Conduct set forth in Attachment F to the ISO OATT.

6.3 Disclosure of Bid Information

Pursuant to Commission requirements, the ISO shall make public Bid information from the Energy, Capacity and Ancillary Services markets, including Bids submitted for Virtual Transactions, but not the names of the bidders making any of these Bids, three months after the Bids are submitted. The ISO shall post the data in a way that permits third parties to track each individual bidder's Bids over time. Prior to such disclosure, Bid information submitted to the ISO by Market Participants shall be considered Confidential Information.

6.4 Survival

This Article 6 will survive the termination of the ISO Services Tariff and any associated Service Agreement.

7 Billing and Payment

7.1 ISO as Counterparty; Right to Net or Set Off; ISO Clearing Account

7.1.1 ISO as Counterparty

The ISO shall be for all purposes the contracting counterparty, in its own name and right, to each Customer for any purchase or sale of any product or service, or for any other transaction, that is financially settled by the ISO under the ISO Tariffs.

7.1.2 Right to Net or Set Off Obligations Owed

Unless otherwise specifically set forth in this ISO Services Tariff, if for any settlement period the ISO is required to pay any amount to the Customer and the Customer is required to pay any amount to the ISO under this ISO Services Tariff or the ISO OATT, such amounts shall be netted, and the party owing the greater aggregate amount shall pay to the other party the difference between the amounts owed. Additionally, all outstanding payment obligations under this ISO Services Tariff and the ISO OATT between the ISO and the Customer may be netted, offset, set off, or recouped, and payment shall be owed as set forth above.

7.1.3 ISO Clearing Account

The ISO will establish one or more accounts (the "ISO Clearing Account") at a bank or other financial institution, and Customers shall make payments to the ISO or receive payments from the ISO through the ISO Clearing Account in accordance with their settlement information provided by the ISO as described in Section 7.2 of this ISO Services Tariff.

The funds held by the ISO in the ISO Clearing Account shall not be commingled with funds held by the ISO in any other ISO accounts.

7.1.4 ISO Liability for Payment

The obligation of the ISO to pay Customers for monies owed for a given settlement

period shall be limited so that the aggregate liability of the ISO for such payments does not exceed the sum of (i) the aggregate amount paid to or recovered by the ISO from Customers (including by applying a defaulting Customer's financial security) for that settlement period, and (ii) the amount of funds held by the ISO in the Working Capital Fund. The process for declaring and recovering bad debt losses is set forth in Attachment U to the ISO OATT.

7.2 Billing and Payment Procedures

For purposes of this Section 7.2:

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

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

7.2.1 Billing and Settlement Information

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

7.2.2 Invoicing and Payment

7.2.2.1 Weekly Invoice

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

7.2.2.2 Monthly Invoice

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

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

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

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

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

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

7.2.2.3 Payment by the Customer

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

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

7.2.2.4 Payment by the ISO

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

7.2.3 Use of Estimated Data and Meter Data

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

7.2.4 Method of Payment

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

immediately available funds payable to the Customer by the ISO through the ISO Clearing Account or (ii) any other method set forth in ISO Procedures.

7.2.5 TCC Auction Settlements

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

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

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

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

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

7.2.6 Verification of Payments

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

7.2.7 Payments for TSCs

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

7.2.8 Payment for Actual Energy Withdrawals by Energy Storage Resources

A Customer that is participating in the ISO-administered Energy and Ancillary Services markets with an Energy Storage Resource, or an Aggregation containing one or more Energy Storage Resources, will be subject to Day Ahead Market settlements pursuant to Section 4.2.6 and Real Time Market settlements pursuant to 4.5.2, or in the case of a Supplier of Regulation Service pursuant to Rate Schedule 15.3.6.1 of this ISO Services Tariff.

If a Load Serving Entity requires the Energy Storage Resource, including an Energy Storage Resource participating in an Aggregation, to also pay a retail rate for its charging withdrawals, then the ISO shall issue a credit to the affected Customer for the associated Actual

Energy Withdrawals and assess a charge to this Load Serving Entity for the same Actual Energy Withdrawals.

An Energy Storage Resource must identify whether its Energy withdrawals for charging will be invoiced at wholesale or at retail rates as part of the ISO's Customer registration process. After an Energy Storage Resource's initial registration, a Load Serving Entity that possesses the necessary authority must notify the ISO and all affected Energy Storage Resources, including Energy Storage Resources participating in an Aggregation, at least 30 days prior to the start of a month in which it will change how one or more Energy Storage Resources are charged for their Actual Energy Withdrawals (at wholesale or at retail). Advance notice is required to switch from charging at wholesale to charging at retail or *vice-versa*. The ISO shall effectuate the change at the start of a month, after it has been provided the required advance notice.

When an Energy Storage Resource participates as a Co-located Storage Resource, the credit issued to an affected Customer and the corresponding charge assessed to the Load Serving Entity will not include the Energy Storage Resource's charging Energy received from the co-located Generator behind the Co-located Storage Resource's shared Point of Injection/Point of Withdrawal. The credit and offsetting charge shall be calculated as the product of the Actual Energy Withdrawals of the Energy Storage Resource and the time weighted average Real-Time Market LBMP for the hour at the Energy Storage Resource's location.

7.3 Interest on Unpaid Balances

Interest on any unpaid amount whether owed to a Customer or to the ISO (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a (a)(2)(iii). Interest on unpaid amounts shall be calculated from the due date of the bill to the date of payment. Invoices shall be considered as having been paid on the date of receipt of payment by the ISO.

If the ISO is unable to provide settlement information on time due to the action or inaction of the Customer, in addition to any other remedies the ISO may have at law or in equity, the Customer shall pay interest on amounts due, as calculated above, from the first day of the Billing Period following the Billing Period in which charges are accrued to the time of payment of those charges.

7.4 Billing Disputes

This Section 7.4 establishes the process and timeframe for review, challenge, and correction of Customer invoices. For purposes of this Section 7.4, any deadline that falls on a Saturday, Sunday, or holiday for which the ISO is closed shall be observed on the ISO's next business day.

For purposes of this Section 7.4, "finalized" data and invoices shall not be subject to further correction, including by the ISO, except as ordered by the Commission or a court of competent jurisdiction; *provided, however*, that nothing herein shall be construed to restrict any stakeholder's right to seek redress from the Commission in accordance with the Federal Power Act.

Challenges to charges and payments in awards rendered by the ISO to Customers buying or selling TCCs in Centralized TCC Auctions and Reconfiguration Auctions shall be governed by Section 19.10 of Attachment M of the ISO OATT and ISO Procedures and shall not be governed by this Section 7.4.

7.4.1 Settlement Cycle for Services Furnished On and After January 1, 2009

7.4.1.1 ISO Corrections or Adjustments and Customer Challenges to the Accuracy of Settlement Information

Settlement information for services furnished beginning January 1, 2009, and thereafter shall be subject to review, comment, and challenge by a Customer and correction or adjustment by the ISO for errors at any time for up to five (5) months from the date of the initial invoice for the month in which service is rendered as set forth in Section 7.2.2.2 of this ISO Services Tariff and as further provided in Section 7.4.1.2, subject to the following requirements and limitations:

7.4.1.1.1 A Supplier or meter authority may review, comment on, and challenge Aggregation, Generator, tie-line, and sub-zone Load metering data for fifty-five (55) days from the date of the initial invoice for the month in which service is rendered. Following this review period, the ISO shall then have five (5) days to process and correct Aggregation, Generator, tie-line, and sub-zone Load metering data, after which time it shall be finalized.

7.4.1.1.2 The meter authority shall provide to the ISO all LSE bus metering data then available within seventy (70) days from the date of the initial invoice and shall provide any necessary updates to the LSE bus metering data as soon as possible thereafter. The ISO shall post all available LSE bus metering data within approximately seventy-five (75) days from the date of the initial invoice and shall continue to post incoming LSE bus metering data as soon as practicable after it is received.

7.4.1.1.3 The ISO shall post advisory settlement information, including available LSE bus metering data, within ninety (90) days from the date of the initial invoice. Customers may review, comment on, and challenge this settlement information, except for Aggregation, Generator, tie-line, and sub-zone Load metering data, after which the ISO shall process and correct the data and issue a corrected invoice with the regular monthly invoice issued on or about one hundred twenty (120) days from the date of the initial invoice. Following the ISO's issuance of a corrected invoice, Customers may continue to review, comment on, and challenge their settlement information, excepting Aggregation, Generator, tie-line, and sub-zone Load metering data, until the end of the five-month review period.

7.4.1.1.4 The meter authority shall provide to the ISO any final updates or corrections to LSE bus metering data within one hundred thirty (130) days from the date of the initial invoice. The ISO shall then post any updated and corrected LSE bus metering data within one hundred thirty-five (135) days from the date of the initial invoice. Customers may then review, comment on, and challenge the LSE bus metering data for an additional ten (10) days. Following this review period, the ISO shall have five (5) days to process and correct the LSE bus metering data, after which it shall be finalized.

The ISO shall use reasonable means to post metering revisions for review by Customers and to notify Customers of the approaching expiration of review periods. To challenge settlement information contained in an invoice, a Customer shall first make payment in full, including any amounts in dispute. Customer challenges to settlement information shall: (i) be submitted to the ISO in writing, (ii) be clearly identified as a settlement challenge, (iii) state the basis for the Customer's challenge, and (iv) include supporting documentation, if applicable. The ISO shall notify all Customers of errors identified and the details of corrections or adjustments made pursuant to this Section 7.4.1.1.

7.4.1.2 Review and Correction of Challenged Invoices

The ISO shall evaluate a settlement challenge as soon as possible within two (2) months following the conclusion of the challenge period specified in Section 7.4.1.1; *provided, however,* the ISO may, upon notice to Customers within this time of extraordinary circumstances requiring a longer evaluation period, take up to six (6) months to evaluate a settlement challenge. The ISO shall not be limited to the scope of Customer challenges in its review of a challenged invoice and may, at its discretion, review and correct any other elements and intervals of a challenged

invoice, except Load and meter data as specified in Section 7.4.1.1. Corrections to a challenged invoice shall be applied to all Customers that were or should have been affected by the original settlement and shall not be limited to the Customer challenging the invoice; *provided, however,* that the ISO may recover *de minimis* amounts or amounts that the ISO is unable to collect from individual Customers through Rate Schedule 1 of this ISO Services Tariff.

Upon completing its evaluation, the ISO shall provide written notice to the challenging Customer of the ISO's final determination regarding the Customer's settlement challenge. If the ISO determines that corrections or adjustments to a challenged invoice are necessary and can quantify them with reasonable certainty, the ISO shall provide all Customers with the details of the corrections or adjustments within the timeframe established in this Section 7.4.1.2. The ISO shall then provide a period of twenty-five (25) days for Customers to review the corrected settlement information and provide comments to the ISO regarding the implementation of those corrections or adjustments; *provided, however*, that in the event of a dispute resolution proceeding conducted in accordance with Section 7.4.2 of this ISO Services Tariff, this twenty-five (25) day period shall not start or, if it has already started, shall be suspended until the conclusion of the dispute resolution proceeding. Following the conclusion of the dispute resolution proceeding, the ISO shall make any corrections to Customers' settlement invoices that it determines to be necessary and shall then start or re-start the twenty-five (25) day Customer comment period.

If no errors in the implementation of corrections or adjustments are identified during the twenty-five (25) day Customer comment period, the ISO shall issue a finalized close-out settlement ("Close-Out Settlement"), clearly identified as such, in the next regular monthly billing invoice. If an error in the implementation of a correction or adjustment is identified

during the twenty-five (25) day Customer comment period, the ISO shall have one (1) month to make such further corrections as are necessary to address the error and provide Customers with one additional period of twenty-five (25) days to review and comment on the implementation of those further corrections. If an error in the implementation of those further corrections is identified, the ISO shall then have one (1) month to make any final corrections that are necessary and shall issue a finalized Close-Out Settlement in the next regular monthly billing invoice.

7.4.2 Expedited Dispute Resolution Procedures for Unresolved Settlement Challenges

7.4.2.1 Applicability of Expedited Dispute Resolution Procedures

This Section 7.4.2 establishes expedited dispute resolution procedures applicable to address any dispute between a Customer and the ISO regarding a Customer settlement that was not resolved in the ordinary settlement review, challenge, and correction process; *provided, however*, that nothing herein shall restrict a Customer or the ISO from seeking redress from the Commission in accordance with the Federal Power Act.

A Customer may request expedited dispute resolution if it has previously presented a settlement challenge consistent with the requirements of Section 7.4.1.1 of this ISO Services Tariff and has received from the ISO a final, written determination regarding the settlement challenge pursuant to Section 7.4.1.2 of this ISO Services Tariff. The scope of an expedited dispute resolution proceeding shall be limited to the subject matter of the Customer's prior settlement challenge. Customer challenges regarding Aggregation, Generator, tie-line, sub-zone Load, and LSE bus metering data shall not be eligible for formal dispute resolution proceedings under this ISO Services Tariff. To ensure consistent treatment of disputes, separate requests for expedited dispute resolution regarding the same issue and the same service month or months may be resolved on a consolidated basis, consistent with applicable confidentiality requirements.

7.4.2.2 Initiation of Expedited Dispute Resolution Proceeding

To initiate an expedited dispute resolution proceeding, a Customer shall submit a written request to the ISO Chief Financial Officer within eleven (11) business days from the date that the ISO issues a final, written determination regarding a Customer settlement challenge pursuant to Section 7.4.1.2 of this ISO Services Tariff. A Customer's written request for expedited dispute resolution shall contain: (i) the name of the Customer making the request, (ii) an indication of other potentially affected parties, to the extent known, (iii) an estimate of the amount in controversy, (iv) a description of the Customer's claim with sufficient detail to enable the ISO to determine whether the claim is within the subject matter of a settlement challenge previously submitted by the Customer, (v) copies of the settlement challenge materials previously submitted by the Customer to the ISO, and (vi) citations to the ISO Tariffs and other relevant materials upon which the Customer's settlement challenge relies.

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

7.4.2.3 Participation by Other Interested Customers

Any Customer with rights or interests that would be materially affected by the outcome of an expedited dispute resolution proceeding may participate; *provided, however*, that a Customer seeking or supporting a change to the NYISO's determination regarding a Customer settlement challenge must have previously raised the issue in a settlement challenge consistent

with the requirements of Section 7.4.1.1 of this ISO Services Tariff. To participate, such Customer shall submit to the ISO Chief Financial Officer a written request to participate that meets the requirements for an initiating request for expedited dispute resolution within eleven (11) business days from the date that the ISO issues notice of the expedited dispute resolution proceeding. If the ISO determines that the Customer has met the requirements of this Section 7.4.2.3, the ISO will accept the Customer's request to participate in the dispute resolution proceeding.

7.4.2.4 Selection of a Neutral

As soon as reasonably possible following the ISO's acceptance of a Customer's request for expedited dispute resolution under Section 7.4.2.2, the ISO shall appoint a neutral to preside over the proceeding by randomly selecting from a list (i) provided to the ISO by the American Arbitration Association or (ii) developed by the ISO with input from the appropriate stakeholder committee, until an available neutral is found. To the extent possible, the neutral shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues and the financial settlement of electric markets.

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

7.4.2.5 Conduct of the Expedited Dispute Resolution Proceeding

The neutral shall schedule the initial meeting of the disputing parties within five (5) business days of appointment. Except as otherwise provided in this Section 7.4.2, the neutral shall have discretion over the conduct of the dispute resolution process including, but not limited to: (i) requiring the disputing parties to meet for discussion, (ii) allowing or requiring written submissions, (iii) establishing guidelines for such written submissions, and (iv) allowing the participation of Customers that have requested an opportunity to be heard.

Within sixty (60) days of the appointment of the neutral, if the dispute has not been resolved, the neutral shall provide the disputing parties with a written, confidential, and non-binding recommendation for resolving the dispute. The disputing parties shall then meet in an attempt to resolve the dispute in light of the neutral's recommendation. If the disputing parties have not resolved the dispute within ten (10) days of receipt of the neutral's recommendation, the dispute resolution process will be concluded.

Neither the recommendation of the neutral, nor statements made by the neutral or any party, including the ISO, or their representatives, nor written submissions prepared for the dispute resolution process, shall be admissible for any purpose in any proceeding.

7.4.2.6 Allocation of Costs

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

7.5 Customer Default

7.5.1 Events of Default

An event of default ("Default") shall occur in the event a Customer (the "Defaulting Party") shall:

(i) fail to comply with the ISO's creditworthiness requirements and receive notice of such failure;

(ii) fail to comply with Section 8.4 of this Tariff;

(iii) make an assignment or any general arrangement for the benefit of creditors;

(iv) fail to timely make a payment due to the ISO, regardless of whether such payment is in dispute, and receive notice from the ISO of such failure;

(v) fail to cure its default in another independent system operator/regional transmission organization market;

(vi) file a petition or otherwise commence, authorize, or acquiesce in the commencement of a case, petition, proceeding, or cause of action under any bankruptcy or insolvency law or similar law for the protection of debtors or creditors, or have such a petition, case, proceeding or cause of action filed or commenced against it and such case, petition, proceeding or cause of action is not withdrawn or dismissed within thirty (30) days after such filing or commencement;

(vii) otherwise become bankrupt or insolvent (however evidenced);

(viii) be unable or unwilling to pay its debts to third parties as they fall due;

(ix) otherwise become adjudicated a debtor in bankruptcy or insolvent (however evidenced);

(x) be unable (or admits in writing its inability) generally to pay its debts as they become due;

(xi) be dissolved (other than pursuant to a consolidation, acquisition, amalgamation or merger);

(xii) have a resolution passed for its winding-up official management or liquidation (other than pursuant to a consolidation, acquisition, amalgamation or merger);

(xiii) seek or become subject to the appointment of an administrator, provisional liquidator, conservator, assignee, receiver, trustee, custodian or other similar entity or official for all or substantially all of its assets;

(xiv) have a secured party take possession of all or substantially all of its assets or has a distress, levy, execution, attachment, sequestration or other legal process levied, enforced or sued on or against all or substantially all of its assets and such secured party maintains possession, or any such process is not dismissed, discharged, stayed or restrained, in each case within thirty (30) days thereafter;

(xv) cause or subject to any event with respect to which, under the applicable laws of any jurisdiction, said event has an analogous effect to any of the events specified in clauses (iv) to (xii) (inclusive);

(xvi) take any action in furtherance of, or indicating its consent to, approval of, or acquiescence in, any of the foregoing acts; or

(xvii) fail to perform any material covenant set forth in the Tariff or a Service Agreement (other than the events that are otherwise specifically covered in this Section as a separate Event of Default), and such failure is not excused by Force

Majeure or cured within five (5) business days after written notice thereof to the Defaulting Party;

7.5.2 Cure

Unless otherwise provided in Attachment K to this Services Tariff:

(i) A Defaulting Party shall have one (1) business day to cure a Default resulting from its failure to timely make a payment due to the ISO.

(ii) A Defaulting Party shall have two (2) business days to cure a Default resulting from its failure to comply with the ISO's creditworthiness requirements; *provided, however*, that a Customer shall have one (1) business day to cure a default resulting from its failure to comply with the ISO's creditworthiness requirements following termination of a Prepayment Agreement.

7.5.3 ISO Remedies

In addition to any and all other remedies available under the ISO Tariffs or pursuant to law or equity, the ISO shall have the following remedies:

(i) Default. Upon an event of Default and expiration of any cure period, the ISO shall have the right to suspend and/or terminate service to the Defaulting Party and the Service Agreement between the ISO and the Defaulting Party immediately upon notice to the Commission. In addition, in the event of a payment default, the ISO shall have the sole and exclusive right to initiate debt collection procedures against a Customer on account of any such default. The process for declaring and recovering bad debt losses is set forth in Attachment U to the ISO OATT.

(ii) **Financial Distress.** In the event of a reduction in the amount of a Customer's Unsecured Credit (a) by fifty percent (50%) or more as determined in accordance with Section 26.5 of Attachment K to the ISO Services Tariff, or (b) as a result of a material adverse change as determined in accordance with Section 26.14 of Attachment K to the ISO Services Tariff, then the ISO shall have the right to: (1) immediately issue an invoice to such Customer requiring payment within two (2) business days from the invoice date for initial settlements representing the sum of that Billing Period's daily billing data available as of the invoice date, and/or (2) require such Customer to prepay estimated charges weekly for up to twelve months in accordance with ISO Procedures.

(iii) **Default in Another ISO/RTO.** In the event a Customer fails to cure its default in another independent system operator/regional transmission organization market, then the ISO shall have the right to: (1) demand immediate payment by the Customer to the ISO for any amounts owed as of the date of the demand, and/or (2) require the Customer to prepay estimated charges weekly for a minimum of twelve months in accordance with ISO Procedures, and/or (3) reduce or eliminate the amount of the Customer's Unsecured Credit.

(iv) **Two Late Payments**. In the event a Customer fails to pay its invoice when due on two occasions within a rolling twelve (12) month period, then the ISO shall have the right to: (1) require the Customer to prepay estimated charges weekly, based on the charges incurred by the Customer in the previous week, for up to twelve months, and/or (2) reduce or eliminate the amount of the Customer's Unsecured Credit for up to twelve (12) months.

7.5.4 Forward Contracts

By entering into Transactions under this Tariff, the Customer agrees that its Service Agreement and Transactions under this Tariff shall constitute a "forward contract" within the meaning of the United States Bankruptcy Code.

7.5.5 Notice to Customers

The ISO shall notify all Customers in the event that a Customer is in default and shall also notify all Customers in the event that the Customer subsequently cures the default or the ISO terminates the Customer due to the default. In the event of a payment default or creditworthiness default, the ISO will disclose in its notice to Customers the approximate amount of the default as follows:

Default Amount	Type of Default	
Range	Payment	Creditworthiness
$0 to $100,000		
$100,001 to $500,000		
$500,001 to $1,000,000		
$1,000,001 to $5,000,000		
$5,000,001 to $10,000,000		
> $10,000,000		

In addition, in the event of a payment default, unless otherwise precluded, the ISO will also disclose the amount and type of collateral, if any, held by the ISO to secure the defaulting Customer's obligations to the ISO.

7.6 Survival

This Article 7 will survive the termination of the ISO Services Tariff and any associated Service Agreement.

8 Eligibility For ISO Services

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

8.1 Requirements Common to all Customers

8.1.1 Creditworthiness

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

8.1.2 Completed Application and Minimum Technical Requirements

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

8.1.3 Additional Eligibility Requirements for all Customers

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

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

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

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

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

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

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

8.2 Additional Requirements Applicable to Suppliers

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

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

8.3 Additional Requirements Applicable to LSEs

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

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

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

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

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

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

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

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

tangible personal property or services in New York State; or

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

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

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

8.4.2 Customer's change in status.

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

8.4.2.2 If a Customer's status as an exempt organization under New York State Tax Law is revoked, suspended, cancelled, surrendered or otherwise terminated or expires, or,

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

8.4.3 Agent's change in status.

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

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

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

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

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

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

9 Application And Registration Procedure

9.1 Application

Each Customer requesting to schedule, take or provide any services under the ISO Services Tariff must apply to the ISO in writing at least sixty (60) days in advance of the month in which service is to commence. The ISO will consider requests for such services on shorter notice when feasible. Service commencement will depend on the ISO's ability to accommodate the request. To apply, the Customer shall complete and deliver a Service Agreement (in the form of Attachment A) and an Application to the ISO.

9.2 Completed Application

A Completed Application shall provide all of the information reasonably required by the ISO to permit the ISO to perform its responsibilities under the ISO Services Tariff. A Customer taking or providing service under the Tariff shall provide the ISO, upon application for service, with a list identifying its parent company as well as any Affiliate. The Customer shall notify the ISO within 30 days of the effective date of any change to the original list. Any Customer shall notify the ISO within 30 days of the effective date of any change to the original list. Any Customer shall respond within 10 days to a request by the ISO to update the list of Affiliates and/or parent company. In addition, a Customer and an applicant seeking to become a Customer shall inform the ISO of any Affiliates that are currently taking service or applying to take service under the Tariffs. The ISO shall treat the information provided in the Application as Confidential Information except to the extent that disclosure of the information is required by the ISO Services Tariff, by regulatory or judicial order or for reliability purposes pursuant to Good Utility Practice. The ISO also shall treat the information in conformity with the standards of conduct contained in Part 37 of the Commission's Regulations and the Code of Conduct set forth

in Attachment F to the ISO OATT.

9.3 Approval of Application and/or Notice of Deficient Application

The ISO will promptly review the Application, including the information provided pursuant to Section 26.1.4 of Attachment K of the ISO Services Tariff, and may request additional information to determine whether the applicant meets the ISO's minimum financial and technical requirements. The ISO will notify the applicant within thirty (30) days of receipt of a Completed Application. If the ISO rejects an Application, the ISO shall provide a written explanation within fourteen (14) days of the rejection. The ISO will attempt to remedy minor deficiencies in the Application through informal communications with the applicant. If such efforts are unsuccessful, the ISO shall return the Application. As set forth in Section 26.1.4 of Attachment K of the ISO Services Tariff, the ISO may reject an application if the ISO determines that the applicant's participation in the ISO Administered Markets presents an unreasonable credit risk.

9.4 Filing of Service Agreement

The ISO will file Service Agreements with the Commission in compliance with applicable Commission regulations and the ISO Services Tariff.

10 Recordkeeping and Audit

The ISO and each Customer shall keep complete and accurate records of service taken or provided under the ISO Services Tariff including, but not limited to, meter readings (if any), dispatch logs, Bid data and other memoranda of Applications and service. Upon thirty (30) days prior written notice, and subject to the provisions in Article 6, the Customer, the ISO, the applicable Transmission Owner, the NYSRC, the Commission or the PSC shall have the right to inspect all records, meter readings and memoranda for the purpose of ascertaining the accuracy of all settlement information prepared pursuant to Article 7 and in compliance with the provisions of the ISO Services Tariff and the Reliability Rules. These inspections shall be performed in a reasonable manner and so as to avoid disrupting the business of the party whose records are being inspected. The costs of all these inspections, including the costs of the party whose records are being inspected, shall be borne by the inspecting party, except that there shall be no charge to the PSC or the Commission for such inspections or for the costs associated with such inspections. Historical records shall be kept as follows: (i) settlement information rendered under the ISO Services Tariff shall be maintained for at least twenty-four (24) months from the date that settlement information is rendered; (ii) Applications under the ISO Services Tariff shall be maintained for twelve (12) months after the date of termination of the service or twelve (12) months after the Application was rejected; and (iii) any other records associated with service under the ISO Services Tariff that are not listed above shall be maintained for twelve (12) months after the date of termination of the service.

11 Dispute Resolution Procedure

11.1 Purpose and Applicability of Dispute Resolution Procedure

11.1.1 Purpose and General Provisions

A party, or parties, and the ISO, having a dispute involving service under the ISO Market Administration and Control Area Services Tariff ("Services Tariff") or the Open Access Transmission Tariff ("OATT"), ISO Procedures, or any Agreement entered into under either Tariff**,** may utilize the provisions of this Section 11 for resolution. The purpose of the dispute resolution processes provided herein is to avoid litigation when possible, and to pursue resolution of the dispute in the most cost-effective and prompt method possible.

Nothing herein restricts the rights of any party or the ISO to file a complaint or seek any other remedy from the Commission under the relevant provisions of the Federal Power Act.

11.1.2 Exceptions

This Article 11 shall not apply to the following disputes, which shall be resolved in accordance with the provisions of the ISO Tariffs, or otherwise, as indicated below:

(i) disputes regarding the Standard Large Facility Interconnection Procedures, Standard Large Generator Interconnection Agreement, Small Generator Interconnection Procedures, Standard Small Generator Interconnection Agreement, Standard Interconnection Procedures, or Standard Interconnection Agreement, which disputes shall be governed by Attachment HH to the ISO OATT;

(ii) disputes regarding the Local Transmission Planning Procedures, which disputes shall be governed by Section 31.2.1.3 of Attachment Y to the ISO OATT;

(iii) disputes over cost estimates provided in interconnection agreements as established in Attachment S or HH, which disputes shall be resolved under the interconnection agreement;

(iv) disputes regarding a Customer's settlements that were not resolved in the ordinary settlement review, challenge, and correction process, which disputes shall be governed by Section 7.4 of this ISO Services Tariff or Sections 2.7.4.2 or 2.7.4.3 of the ISO OATT;

(v) disputes regarding certain ICAP-related issues that Section 5 of the ISO Services Tariff expressly indicates shall be governed by other provisions of the ISO Services Tariff;

(vi) disputes regarding Centralized TCC Auction or Reconfiguration Auction awards, which disputes shall be governed by Attachment M, Section 19 of the ISO OATT;

(vii) disputes involving applications for changes in rates, changes in terms or conditions of service, or other changes to the ISO Tariffs, ISO Procedures, or agreements to which the ISO is a party and disputes that may result in an obligation to transmit electricity under circumstances where the Commission is precluded from ordering transmission service pursuant to FPA Section 212(h). Parties with these disputes have exclusively those rights provided for under the FPA or otherwise provided by law and have no right to invoke dispute resolution processes under this Section 11.

11.2 Initiation of Dispute Resolution Proceedings

11.2.1 Notice of Dispute

In the event of a dispute that the party or parties have been unable to resolve, any party or parties may initiate a dispute resolution proceeding pursuant to this Article 11 ("Dispute Resolution Proceeding") by submitting a written notice to the ISO. The written notice shall describe the dispute in detail and set forth the factual and legal assertions underlying the dispute (including specific reference to applicable provisions of the ISO Tariffs, or ISO Procedures, or relevant Service Agreements), and shall designate one or more authorized representatives of each of the party or parties initiating the dispute to participate in the Dispute Resolution Proceeding on their behalf.

11.2.2 Parties to Dispute Resolution Proceeding

The party or parties initiating the dispute pursuant to the provisions of Section 11.2.1 and the ISO shall be parties to the Dispute Resolution Proceeding ("Parties").

11.3 Informal Discussions

Within thirty (30) days of written notice of the dispute pursuant to Section 11.2.1, senior representative(s) of each Party shall attempt in good faith to fully and finally resolve the dispute through informal discussions.

11.4 Available Formal Proceedings

In the event the Parties are unable, through informal discussions in accordance with Section 11.3 to resolve the dispute within thirty (30) days after the NYISO receives written notice of the dispute, then:

11.4.1

Upon their express written agreement, the Parties may submit all or some portion of the dispute to non-binding mediation as specified in Section 11.5; or

11.4.2

The Parties, upon their express written agreement, may submit all or some portion of the dispute to arbitration as specified in Section 11.6, provided however, if the mediation procedures are used, the Parties may submit all or some portion of the dispute to arbitration only after the conclusion of mediation that does not resolve the dispute; or

11.4.3

The Parties may commence legal proceedings before the Commission, or a court of competent jurisdiction as to any matter not within the primary or exclusive jurisdiction of the Commission, for purposes of adjudicating all or some portion of the dispute; provided, however, that if the Parties agreed in writing to submit the dispute to non-binding mediation, termination of the mediation, as certified in writing by the mediator selected by the parties, is a condition precedent to the commencement of any legal proceeding, except to the extent necessary to preserve a claim subject to expiration under an applicable statute of limitations.

11.5 Non-Binding Mediation

If the Parties agree to submit all or some portion of the dispute to non-binding mediation, as specified in Section 11.4.1, they shall do so either (i) pursuant to a written agreement setting forth or adopting all necessary terms, conditions and rules of procedure governing the mediation as agreed by the Parties, or (ii) pursuant to a written agreement adopting the procedures of 11.5.1 through 11.5.3:

11.5.1 Selection of a Mediator

Within ten (10) days of the Parties' written agreement to mediate, the Parties shall exchange lists of proposed mediators, and the Parties shall seek to agree on a mediator.

Any individual designated as the mediator shall make known to the Parties whether he or she is a past or present officer, employee or consultant to any of the Parties, or of any entity related to or Affiliated with any of the Parties or is otherwise interested in the matter to be mediated. Any person with such a relationship shall not be eligible to serve as the mediator, absent the express written consent of all Parties.

If the Parties are unable to agree on a mediator, they shall invoke the assistance of the Commission's Dispute Resolution Service to select a mediator.

11.5.2 Scope of Mediator's Duties

The disputing parties shall attempt in good faith to resolve their dispute in accordance with the schedule established by the mediator but in no event, may the schedule extend beyond ninety (90) days from the date of appointment of the mediator.

The mediator may require the disputing parties to:

1. submit additional written statements of issue(s) and position(s), along with supporting documents or affidavits;
2. meet for discussions; and/or
3. comply with additional mediation procedures designated by the mediator.

If the Parties have not resolved the dispute within ninety (90) days after the date the mediator was appointed, then the mediator shall promptly provide the Parties with a written, confidential, non-binding recommendation to resolve the dispute. The recommendation shall include an assessment by the mediator of the merits of the principal positions being advanced by each of the Parties. The Parties shall then meet in a good faith attempt to resolve the dispute in light of the mediator's recommendation. This recommendation shall be limited to resolving the specific issues presented for mediation.

The recommendation of the mediator, and any other statements made by any Party during the mediation process, shall not be admissible for any purpose, in any subsequent proceeding.

11.5.3 Costs

Each Party will bear an equal share of the costs associated with the time, expenses and other charges of the mediator. Each Party shall bear its own costs, including attorney and expert fees.

11.6 Arbitration

If the Parties agree in writing to submit all or some portion of the dispute to arbitration as specified in Section 11.4.2, they shall do so either (i) pursuant to a written agreement invoking the assistance of the Commission Dispute Resolution Service in reaching an agreement on the selection of a neutral arbitrator or arbitrators, and the adoption of all necessary terms, conditions and rules of procedure to govern an arbitration or other resolution of the dispute, or (ii) pursuant

to a written agreement adopting the procedures of 11.6.1. Only if all Parties include in their agreement, submitting all or a portion of their dispute to arbitration, that the decision of the arbitrator shall be final and binding on the Parties, shall such decision be final and binding on the Parties whether they choose to pursue the arbitration pursuant to 11.6(i) or 11.6(ii).

11.6.1 Procedural Provisions

11.6.1.1 Selection of an Arbitrator

Within ten (10) days of the date the Parties submit a written agreement to invoke the arbitration provisions of this Section 11.6, and unless such written agreement has invoked the Commission's Dispute Resolution Service pursuant to Section 11.6, the Parties shall exchange lists of qualified arbitrators. No person shall be eligible for selection as an arbitrator who is a past or present officer, employee of or consultant to any of the Parties, or of an entity related to or affiliated with any of the Parties, or is otherwise interested in the matter to be arbitrated, except upon the express written consent of the Parties. Any individual designated as an arbitrator shall make known to the Parties any such disqualifying relationship or interest and a new arbitrator shall be designated, unless express written consent is provided by each Party.

If the Parties cannot agree upon an arbitrator, the Parties shall invoke the services of the Commission's Dispute Resolution Service in the selection of an arbitrator.

11.6.1.2 Scope of Arbitrator's Duties

The arbitrator shall have no power to modify or change any agreement, tariff or rule or otherwise create any additional rights or obligations for any Party. The scope of the arbitrator's decision shall be limited to the issues presented for arbitration. The arbitrator shall determine discovery procedures, intervention rights, how evidence shall be taken, what written submittals may be made, and other such procedural matters, taking into account the complexity of the issues

involved, the extent to which factual matters are disputed, and the extent to which the credibility of witnesses is relevant to a resolution. Each Party shall produce all evidence determined by the arbitrator to be relevant to the issues presented. To the extent such evidence involves proprietary or Confidential Information, the arbitrator may issue an appropriate protective order which shall be complied with by all Parties. The arbitrator may elect to resolve the arbitration matter solely on the basis of written evidence and arguments.

The arbitrator shall consider all issues underlying the dispute, and the arbitrator shall take evidence submitted by the Parties in accordance with procedures established by the arbitrator and may request additional information including the opinion of recognized technical bodies or experts. The Parties shall be afforded a reasonable opportunity to rebut any such additional information.

Absent agreement to the contrary by all Parties, no person or entity that is not among the Party or Parties initiating the dispute pursuant to Section 11.2.1 of this Tariff shall be permitted to intervene, but see Section 11.7 concerning consolidation of separate disputes.

11.6.2 The Arbitration Decision

Within ninety (90) days of the appointment of the arbitrator, and after providing the parties with an opportunity to be heard, the arbitrator shall render a written decision, including findings of fact and the legal basis for the decision. The arbitrator will follow the Commercial Arbitration Rules of the American Arbitration Association.

If the arbitrator concludes that no proposed award is consistent with the ISO Services Tariff, the ISO OATT, the FPA and Commission's then-applicable standards and policies, or would address all issues in dispute, the arbitrator may determine no award is available or the arbitrator may develop a compromise solution consistent with the terms of the ISO Services

Tariff, the ISO OATT or the FPA. In all cases, the arbitrator shall provide to the Parties a written decision including findings of fact and explaining the basis for the award, the basis for the compromise award or, if no award is available, the basis for the decision that no award is available. No award shall be deemed to be precedential in any other arbitration related to a different dispute.

11.6.3 Costs

All costs associated with the time, expenses and other charges of the arbitrators shall be borne by the unsuccessful Party. Each Party shall bear its own costs, including attorney and expert fees.

11.6.4 Filing and Finality.

All arbitration decisions that affect matters subject to the jurisdiction of the Commission shall be filed with the Commission. Any arbitration decision that affects matters subject to the jurisdiction of the PSC under the PSL may be filed with the PSC. The judgment of the arbitrator, agreed to be final and binding by written agreement of the Parties, pursuant to Section 11.6, may be entered on the award by any court in New York having jurisdiction.

Within one (1) year of the arbitration decision, a Party may request that the Commission or any other federal, state, regulatory or judicial authority (in the State of New York) having jurisdiction over such matter vacate, modify or take such other action as may be appropriate with respect to any arbitration decision that is:

1. based upon an error of law;
2. contrary to the statutes, rules or regulations administered by such authority;
3. violative of the Federal Arbitration Act or Administrative Dispute Resolution Act; or

4. based on conduct by an arbitrator that is violative of the Federal Arbitration Act or Administrative Dispute Resolution Act.

11.7 Consolidation of Related Arbitration Proceedings

Upon the written consent of all Parties who have agreed to arbitration of a dispute pursuant to Sections 11.4.2 and 11.6, and with the consent of all Parties to pending arbitration proceedings commenced pursuant to the same provision, such arbitration proceedings may be consolidated if the disputes in each proceeding (i) arise out of or relate to essentially the same set of facts or fact pattern, series or type of transactions or legal issues, and (ii) are governed by the same provisions of the ISO Tariffs and applicable law, provided however, arbitration proceedings which the Parties have agreed, pursuant to Section 11.6, shall result in a final and binding decision shall be consolidated, to the extent otherwise permitted by this section, only with other arbitration proceedings which the Parties have agreed, pursuant to Section 11.6, shall result in a final and binding decision. Any Party to an arbitration proceeding who agrees to consolidation as provided herein may not, and forever waives any right to, challenge a final award, in whole or in part, whether on appeal or otherwise, on the ground that it was prejudiced or deprived of any right by virtue of the consolidation.

11.8 Ongoing Duty to Perform

The pendency of a Dispute Resolution Proceeding under this Article 11 shall not relieve the Parties of any duty to perform their respective obligations under the ISO Tariffs, ISO Procedures, or relevant agreement.

11.9 Rights Under the Federal Power Act

Nothing in Section 11 of this Tariff shall restrict the rights of any Party to file a complaint, rate or tariff or other contract change with the Commission under the relevant provisions of the Federal Power Act. No arbitrator shall select an award which requires the transmission of electricity under circumstances where the Commission is precluded from ordering Transmission Services pursuant to FPA Section 212(h).

12 Liability and Indemnification

12.1 Force Majeure

The ISO, the NYSRC, the Transmission Owners and any Customer or Market Participant shall not be considered to be in default or breach under the ISO Services Tariff or a Service Agreement, and shall be excused from performance, or liability for damages to any other party, if and to the extent it shall be delayed in or prevented from performing or carrying out any of the provisions of the ISO Services Tariff or a Service Agreement, except the obligation to pay any amount when due, arising out of or from any act, omission or circumstance occasioned by or in consequence of any act of God, labor disturbance, failure of contractors or suppliers of materials, act of the public enemy, war, invasion, insurrection, riot, fire, storm, flood, ice, explosion, breakage or accident to machinery or equipment, or by any other cause or causes beyond such party's reasonable control, including any Curtailment, order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or by the making of repairs necessitated by an Emergency circumstance not limited to those listed above upon the property or equipment of the ISO or any party to the ISO Agreement. Nothing contained in this section shall relieve any entity of the obligation to make payments when due hereunder or pursuant to a Service Agreement. Any party claiming a force majeure event shall use reasonable diligence to remove the condition that prevents performance, except the settlement of all labor disturbances shall be in the sole judgment of the affected party.

Nothing contained in this section shall relieve a party to a Service Agreement of its obligations to pay all charges due under the Tariff, even if such charges would not have been due had the party claiming force majeure not experienced the force majeure.

12.2 Claims by Employees and Insurance

Each Transmission Owner, Customer, Market Participant and the ISO shall be solely responsible for and shall bear all of the costs of claims by its own employees, contractors, or agents arising under, and covered by, any workers' compensation law. Each of the parties shall furnish, at its sole expense, such insurance coverage and such evidence thereof, or evidence of self-insurance, as is reasonably necessary to meet its obligations under this section.

12.3 Limitation on Liability

The ISO, Transmission Owners and NYSRC shall not be liable (whether based on contract, indemnification, warranty, tort, strict liability or otherwise, to any Customer, Market Participant, or any third party or other party for any damages whatsoever including, without limitation, direct, incidental, consequential, punitive, special, exemplary or indirect damages resulting from any act or omission in any way associated with a Service Agreement or the ISO Services Tariff, except to the extent that the ISO, Transmission Owner or NYSRC is found liable for gross negligence or intentional misconduct, in which case the ISO, Transmission Owner or NYSRC will not be liable for any incidental, consequential, punitive, special, exemplary or indirect damages. This section, however, does not limit in any way the ISO's obligation to indemnify the Transmission Owners pursuant to the ISO/TO Agreement or any other agreement.

Nothing in the ISO Services Tariff, or any Service Agreement pursuant to the ISO Services Tariff, express or implied, is intended to confer on any person, other than the parties to a Service Agreement, any rights or remedies under or by reason of the ISO Services Tariff.

The protections provided to the ISO, Transmission Owners and NYSRC in this Section 12.3 regarding limitation of liability and damages shall be applicable to Generators acting in good faith to implement or comply with the directives of the ISO, Transmission Owner or

NYSRC.

12.4 Indemnification

For the purpose of this section, the terms Market Participant(s) and Customer(s) shall not include a Transmission Owner with respect to acts or omissions related in any way to the Transmission Owner's ownership or operation of its transmission facilities when such acts or omissions are either (1) pursuant to or consistent with ISO Procedures or direction or (2) in any way related to the Transmission Owner's or the ISO's performance under this Tariff.

Subject to the ISO's obligations to the Transmission Owners under the ISO/TO Agreement, the Operating Agreements, and/or the ISO Agreement, each Customer and Market Participant shall indemnify, save harmless and defend the ISO, the Transmission Owners and the NYSRC including their directors, members, managers, officers, employees, trustees, committee members and agents, or each of them (individually the "Indemnitee" or collectively the "Indemnitees") from and against all claims, demands, losses, liabilities, judgments, damages, and related costs and expenses (including, without limitation, reasonable attorney and expert fees, and disbursements incurred by the Indemnitees in any actions or proceedings between the Indemnitees and a third party, the Customer or Market Participant or any other party) arising out of or related to the Indemnitee's or the Customer's acts or omissions related in any way to performance under the ISO Services Tariff, a Service Agreement, an ISO Related Agreement, or ISO Procedures except to the extent that the Indemnitees are found liable for gross negligence or intentional misconduct.

The ISO will procure insurance or other alternative risk financing arrangements sufficient to cover the risks associated with the carrying out of its responsibilities under this Tariff. The proceeds from such insurance shall be used prior to the invocation by the ISO of its right to

indemnification under this section through the Rate Schedule 1 charge. Except to the extent that indemnification of the ISO is required from a particular Market Participant or Customer because of the acts or omissions of that Market Participant or Customer, indemnification of or by the ISO shall be effected through the Rate Schedule 1 charge of the ISO OATT.

Nothing in this section shall preclude the ISO from seeking indemnification of penalty costs against Customers and Market Participants, including Transmission Owners, as provided in Schedule 11 of the ISO OATT, except that the ISO shall not be indemnified in instances of its gross negligence or intentional misconduct.

12.5 Other Remedies

Nothing in the ISO Services Tariff shall be construed as in any way to limit the Transmission Owner's rights and remedies, at law or in equity, with respect to a party in the event of an act or omission related to the ISO Services Tariff by such party.

12.6 Survival

The provisions of this Article 12, "Liability and Indemnification," shall survive termination or expiration of the ISO Services Tariff or any associated Service Agreement.

13 Metering

13.1 General Requirements

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

13.2 Requirements Pertaining to Customers

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

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

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

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

13.2.1 Load Serving Entities

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

13.2.2 Ancillary Service Suppliers

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

13.2.3 Estimation of Metering

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

13.2.4 Energy Storage Resources

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

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

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

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

The ISO Procedures, including the Revenue Meter Requirements Manual (M-25), Control Center Requirements Manual (M-21), and Accounting and Billing Manual (M-14)

contain additional information related to metering requirements for Generators and Energy Storage Resources.

13.3 Metering Requirements for DER Aggregations and Demand Side Resources

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

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

13.3.1.2 The Aggregator, Responsible Interface Party or Curtailment Service Provider shall be responsible for ensuring that all of the metering and meter data services that are required for it to perform its functions and fulfill its responsibilities under the ISO Tariffs and ISO Procedures are provided by the Member System, municipal electric utility, and/or Meter Services Entity in

accordance with the requirements in this Section 13 and ISO Procedures. The Aggregator, Responsible Interface Party, or Curtailment Service Provider shall be responsible for any applicable penalties issued as a result of metering or meter data services that do not comply with the ISO Tariffs and ISO Procedures, including, but not limited to, penalties issued pursuant to Services Tariff Sections 5.12 and 5.14.

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

13.3.1.4 All individual Resources within an Aggregation must use the same Meter Authority. A DER Aggregation may use either the applicable Member System, municipal electric utility, or a qualified Meter Services Entity as its Meter Authority. Single Resource Type Aggregations (*e.g.*, an Aggregation comprised of only Energy Storage Resources) may only use the applicable Member System.

13.3.2 Meter Services Entity Requirements

13.3.2.1 Eligibility Determination for Meter Services Entity

To be authorized as a Meter Services Entity, an entity must complete, to the NYISO's satisfaction, the application requirements specified in Services Tariff Section 13.3.2.1.2 below. Once authorized, a Meter Services Entity must meet the obligations set forth in Services Tariff

Sections 13.3.2.1.3 and 13.3.2.1.4. All physical metering infrastructure and meter data communications infrastructure used by a Meter Services Entity must comply with the requirements set forth in the ISO Tariffs and ISO Procedures.

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

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

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

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

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

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

13.3.2.2 Standards of Conduct for Meter Services Entities

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

13.3.2.3 ISO Audits and Corrective Actions

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

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

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

B) Site meter configurations;

C) Meter compliance with ISO rules and procedures;

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

E) Telemetry and communication data and records.

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

13.3.3 Metering Requirements for Aggregated Resources

Aggregators shall ensure that all measurements for metering and telemetry for the individual DER they represent, derive from either directly measured or calculated values, or a combination thereof, in accordance with the requirements set forth in ISO procedures.

14 Miscellaneous

14.1 Notices

Except as specified in the ISO Procedures, all written notices under the ISO Services Tariff shall be deemed as having been given: (i) when delivered in person; (ii) when sent by United States registered or certified mall (return receipt requested), postage prepaid, or (iii) when sent by a reputable overnight courier to the other party at the address stated in the Service Agreement between the ISO and each Customer or at the last changed address given by the other party as hereinafter specified. Either party may, at any time, change its address for notification purposes by sending the other party written notice stating the change and setting forth the new address. The ISO shall adopt procedures for the provision of all notices and protocols required to implement the ISO Services Tariff.

14.2 Tax Exempt Financing Pursuant to Section 142 (f) of the Internal Revenue Code

This provision is applicable only to Transmission Owners that have financed facilities for the local furnishing of Energy with Local Furnishing Bonds as described in Section 142(f) of the Internal Revenue Code ("Local Furnishing Bonds"). Notwithstanding any other provision of the ISO Services Tariff, neither the ISO nor the Transmission Owner shall be required to take any action or provide any service if the taking of such action or provision of such service would result in loss of the tax-exempt status of any Local Furnishing Bonds. In the event a Transmission Owner is ordered to take an action on behalf of a Customer that results in the loss of tax-exempt status of any Local Furnishing Bonds, such Customer shall be obligated to pay to the Transmission Owner all costs associated with the loss of tax-exempt status of the Local Furnishing Bonds.

14.3 LIPA and NYPA Tax Exempt Obligations

This provision is applicable to LIPA and NYPA, which have financed transmission facilities with the proceeds of tax-exempt bonds issued pursuant to the Internal Revenue Code. Notwithstanding any other provision of the ISO OATT or the ISO Services Tariff, neither the ISO nor the Transmission Owner shall be required to provide Transmission Service to any Customer pursuant to an ISO Tariff if the provision of such Transmission Service would result in loss of tax-exempt status of the NYPA Tax Exempt Bonds or LIPA Tax Exempt Bonds or impair LIPA's or NYPA's ability to issue future tax-exempt obligations. If, by virtue of an order issued by the Commission pursuant to Section 211 of the FPA, the ISO or a Transmission Owner is required to provide Transmission Service that would adversely affect the tax-exempt status of the LIPA Tax Exempt Bonds or NYPA's Tax Exempt Bonds or any other tax-exempt debt obligations, then the Customer receiving such Transmission Service will compensate LIPA or NYPA for all costs, if any, associated with the loss of tax-exempt status plus the normal costs of Transmission Service.

14.4 Amendments

Nothing contained in the ISO Services Tariff or any Service Agreement shall be construed as affecting in any way the right of the ISO or a Transmission Owner under the ISO/TO Agreement or an Operating Agreement to make application to the Commission for a change in: rates, terms, conditions, charges, or classifications of service; the provision of Ancillary Services; a Service Agreement; or a rule or regulation, under the FPA and pursuant to the Commission's rules and regulations promulgated thereunder.

Nothing contained in the ISO Services Tariff of any Service Agreement shall be construed as affecting in any way the ability of any Transmission Customer or Transmission

Owner to exercise its rights under the FPA including, but not limited to, the right to file a complaint under Section 206 of the FPA or any successor statute and pursuant to the Commission's rules and regulations promulgated thereunder.

Notwithstanding any other provision of the ISO Services Tariff, the ISO Services Tariff may be amended only in accordance with the ISO Agreement, the ISO/TO Agreement, and consistent with the requirements of the FPA and the Commission's rules and regulations promulgated thereunder.

14.5 Applicable Law and Forum

The ISO Services Tariff and any Service Agreement shall be governed by and construed in accordance with the law of the State of New York, except its conflict of law provisions. Customers irrevocably consent that any legal action or proceeding arising under or relating to the ISO Services Tariff or any Service Agreement shall be brought in any court of the State of New York or any federal court of the United States of America located in the State of New York.

Customers irrevocably waive any objection that they may now or in the future have to the designated courts in the State of New York as the proper and exclusive forum for any legal action or proceeding arising under or relating to the ISO Services Tariff or any Service Agreement.

14.6 Counterparts

Any Service Agreement entered into pursuant to the ISO Services Tariff may be executed in several counterparts, each of which shall be an original and all of which shall constitute one and the same instrument.

14.7 Waiver

No delay or omission in the exercise of any right under a Service Agreement or the ISO Services Tariff shall impair any such right or shall be taken, construed or considered as a waiver or relinquishment thereof, but any such right may be exercised from time-to-time and as often as may be deemed expedient. If any obligation or covenant under a Service Agreement or the ISO Services Tariff shall be breached and thereafter waived, such waiver shall be limited to the particular breach so waived and shall not be deemed to waive any other breach hereunder or under a Service Agreement.

14.8 Assignment

Obligations under the ISO Services Tariff and any Service Agreement shall be binding on the successors and assigns of the Service Agreement. No assignment shall relieve the original Customer from its obligations under the ISO Services Tariff or any Service Agreement.

14.9 Representations, Warranties & Covenants

A Service Agreement entered into under the ISO Services Tariff shall contain representations, warranties and covenants, as the parties deem appropriate and in accordance with the pro forma Service Agreement, regarding the Customer's ability to perform, and the enforceability of, the Service Agreement.

15 ISO Market Administration and Control Area Service Tariff Rate Schedules

15.1 Rate Schedule 1 - ISO Annual Budget Charge and Other Non-Budget Charges and Payments

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

15.2 Rate Schedule 2 - Payments for Supplying Voltage Support Service

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

Suppliers provide Voltage Support Service from eligible providers, which are Generators with an automatic voltage controlling equipment ("Generators," for the purpose of this Rate Schedule 2), synchronous condensers, and Qualified Non-Generator Voltage Support Resources. Aggregations are not eligible to provide Voltage Support Service.

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

15.2.1 Responsibilities

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

15.2.1.1 Suppliers

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

Voltage Support Service includes the ability to produce or absorb Reactive Power within the Voltage Support Resource's tested reactive capability, and the ability to maintain a specific voltage level under both steady-state and post-contingency operating conditions subject to the limitations of the Voltage Support Resource's stated reactive capability. The requirement for a Voltage Support Resource to absorb Reactive Power may be set aside by the ISO with input from the Transmission Owner in whose Transmission District the Voltage Support Resource is

located, which input may include, at the Transmission Owner's option, an executive level review. To grant an exemption from the requirement that the Voltage Support Resource be able to absorb Reactive Power, the ISO shall have determined that: 1) the Voltage Support Resource is unable, due to transmission system configuration, to absorb Reactive Power; 2) the ability of the Voltage Support Resource to produce Reactive Power is needed for system reliability; and 3) for purposes of system reliability the Voltage Support Resource does not need to have the ability to absorb Reactive Power.

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

becoming an Interim Service Provider and shall permit the Interim Service Provider to be a Qualified Supplier of Voltage Support Service.

15.2.2 Payments

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

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

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

15.2.2.1 Annual Payment for Voltage Support Service

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

minus the sum of the lagging and the absolute value of the leading MVAr capacity within the Voltage Support Resource's standard power factor range. For purposes of Voltage Support Service, the standard power factor range for each Voltage Support Resource will be 0.95 lagging to 0.95 leading.

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

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

15.2.2.2 Lost Opportunity Costs

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

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

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

Where:

LOC_i = Lost Opportunity Cost for interval *i*

$LBMP_{RT,i}$ = Real-time LBMP for interval *i*

EOP_i = The Generator's Economic Operating Point for interval *i*

AEI_i = The Generator's Actual Energy Injection for the interval *i*

RTS_i = The Generator's Real-Time Energy Schedule for interval *i*

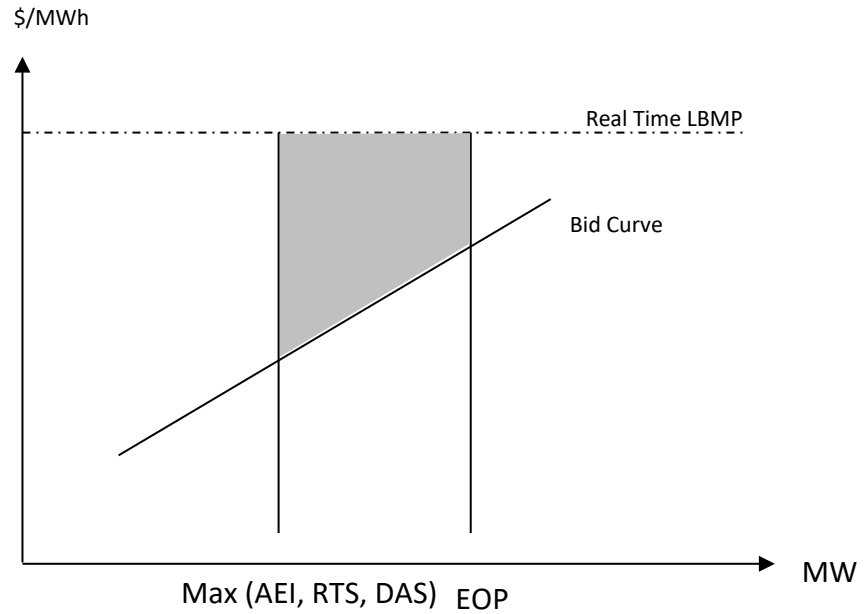
DAS_i = The Generator's Day-Ahead Schedule for the hour containing *i*

Bid_i = Generator's Bid curve in effect for interval *i*

$S_i/3600$ = The length of interval *i*, containing $S_i^{seconds}$ in units of hours

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

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



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

If a synchronous condenser or Qualified Non-Generator Voltage Support Resource energizes in order to provide Voltage Support Service in response to a request from the ISO, the ISO shall compensate the facility for the cost of Energy it consumes to energize converters and other equipment necessary to provide that Voltage Support Service.

15.2.3 Failure to Perform by Suppliers

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

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

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

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

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

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

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

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

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

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

Where:

F = number of failures in the month

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

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

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

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

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

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

Initial Failure: The ISO will withhold from the Supplier one-twelfth (1/12th) of the annual payment for the specific Voltage Support Resource (or an amount equal to the last month's voltage support payment made to it, if it is not an Installed Capacity provider).

Second Failure within the same thirty (30) day period: The ISO shall withhold from the Supplier one-fourth (1/4th) of the annual payment for the specific Voltage Support Resource (or an amount equal to the last three (3) months' voltage support payments made to it, if it is not an Installed Capacity provider). In addition, the Supplier that is in violation shall be prohibited from receiving Voltage Support Service payments for the non-complying Voltage Support Resource until the Supplier complies with the following conditions to the ISO's satisfaction:

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

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

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

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

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

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

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

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

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

15.2.7 Consistence with Cross-Sound Scheduled Line Protocols

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

15.3 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 each 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 each Local Generator uses inverter-based energy storage technology). 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) Choose to opt in or out of the Limiting Participation Flag if the resource is a Combined Cycle Gas Turbine Generator with Duct-Firing Capability.

(c) Provide the ISO with the Resource's Regulation Capacity Response Rate and the Resource's Regulation Movement Response Rate;

(d) 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;

(e) 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;

(f) Pay any charges imposed under this Rate Schedule;

(g) 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.

(f) Regulation Service Offers from Combined Cycle Gas Turbine Generators with Duct-Firing Capability that have opted for the Limiting Participation Flag: The ISO shall limit the Regulation Capacity (in MW) from a Combined Cycle Gas Turbine Generator with Duct Firing Capability, that has opted for the Limiting Participation Flag, to the Resource’s maximum Regulation Service capability without exceeding its Participation Limit.

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:

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

Where:

K_{PIi} = 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.

$$Performance\ Charge_i = (((1 - K_{PIi}) * RTRinccap_i * \text{-}1.1 * RTMPreg_i) + (((1 - K_{PIi}) * (RTRcap_i - RTRinccap_i) * \text{-}1.1) * Max(DAMPreg_, RTMPreg_i))) * (S_i/3600)$$

$DAMPreg_i$ = 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*;

$RTRinccap_i$ = 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:

$$Energy\ Settlements_h = Net\ MWHR_h * LBMP_h$$

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 is 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.

15.3A Rate Schedule "3-A" -Charges Applicable to Suppliers That Are Not Providing Regulation Service

15.3A.1 Persistent Undergeneration Charges

A Supplier, other than a Supplier exempted in Section 15.3A.2 of this Rate Schedule, that is not providing Regulation Service, and persistently operates at a level below its schedule to provide Energy shall pay a persistent undergeneration charge to the ISO, unless its operation is within a tolerance described below, provided, however, no persistent undergeneration charges shall apply to a Fixed Block Unit that has reached a percentage of its Normal Upper Operating Limit, which percentage shall be set pursuant to ISO Procedures and shall be initially set at seventy percent (70%). Persistent undergeneration charges per interval shall be calculated as follows:

$$\text{Persistent undergeneration charge} = \text{Energy Difference} \times \text{Max}(MPRC_{DAM}, MPRC_{RT}) \times \text{Length of Interval in seconds}/3600 \text{ seconds}$$

Where:

Energy Difference in (MW) is determined by subtracting the actual Energy provided by the Supplier from its RTD Base Point Signal for the dispatch interval. The Energy Difference shall be set at zero for any Energy Difference that is otherwise negative or that falls within a tolerance, set pursuant to ISO Procedures, and which shall contain a steady-state and a dynamic component. The steady-state component shall initially be 3% of the Supplier's Normal Upper Operating Limit or Emergency Upper Operating Limit, as applicable, and the dynamic component shall be a time constant that shall initially be set at fifteen minutes;

$MPRC_{DAM}$ is the Regulation Capacity Market Price in the Day-Ahead Market; and

$MPRC_{RT}$ is the Regulation Capacity Market Price in the Real-Time Market.

15.3A.1.1 Overgeneration Charges

An Intermittent Power Resource that depends on wind or solar energy as its fuel, for which the ISO has imposed a Wind and Solar Output Limit, that operates at a level above its schedule shall pay an overgeneration charge to the ISO, unless its operation is within a tolerance described below. An Intermittent Power Resource that depends on landfill gas as its fuel, or a Limited Control Run-of-River Hydro Resource that participates in the ISO-Administered Markets as part of a Co-located Storage Resource, for which the ISO has imposed a Wind and Solar Output Limit, that operates at a level above its schedule shall pay an overgeneration charge to the ISO, unless the Resource's operation is within a tolerance described below.

Overgeneration charges per interval shall be calculated as follows:

$$\text{Overgeneration charge} = \text{Energy Difference} \times \text{Max}(MPRC_{DAM}, MPRC_{RT}) \times \text{Length of Interval in seconds}/3600 \text{ seconds}$$

Where:

Energy Difference in (MW) is determined by subtracting the RTD Base Point Signal for the dispatch interval from the actual Energy provided by the Resource for the same interval. The Energy Difference shall be set at zero for any Energy Difference that is otherwise negative or that falls within a tolerance, set pursuant to ISO Procedures, which shall initially be set at 3% of the Resources' Normal Upper Operating Limit or Emergency Upper Operating Limit, as applicable;

$MPRC_{DAM}$ is the Regulation Capacity Market Price in the Day-Ahead Market; and

$MPRC_{RT}$ is the Regulation Capacity Market Price in the Real-Time Market

15.3A.1.2 Persistent Over-Withdrawal Charges

An Energy Storage Resource, an Aggregation of Energy Storage Resources, or DER Aggregation that includes at least one Withdrawal-Eligible Generator that is (a) scheduled to

withdraw Energy, (b) not providing Regulation Services, and (c) persistently withdrawing Energy at a level exceeding its withdrawal schedule, shall pay a persistent over-withdrawal charge to the ISO unless its operation is within the applicable tolerance described below. Persistent over-withdrawal charges per interval shall be calculated as follows:

Persistent Over-Withdrawal Charge = Energy Difference x Max ($MPRC_{DAM,}$ $MPRC_{RT}$) x Length of Interval in seconds/3600 seconds

Where:

Energy Difference in (MW) is determined by subtracting the Resource's actual energy operating level from its RTD Base Point Signal. The Energy Difference shall be set at zero for any Energy Difference that is otherwise negative or that falls within a tolerance, set pursuant to ISO Procedures, and which shall contain a steady-state and a dynamic component. The steady-state component shall initially be an absolute value of 3% of the Resource's Maximum Withdrawal Limit, as applicable, and the dynamic component shall be a time constant that shall initially be set at fifteen minutes;

$MPRC_{DAM}$ is the Regulation Capacity Market Price in the Day-Ahead Market; and

$MPRC_{RT}$ is the Regulation Capacity Market Price in the Real-Time Market.

15.3A.2 Exemptions

The following types of Generator shall not be subject to persistent undergeneration charges:

15.3A.2.1 Generators, except for the Generator of a Behind-the-Meter Net Generation Resource and a Generator in an Aggregation, providing Energy under contracts (including PURPA contracts), executed and effective on or before November 18, 1999, in which the power purchaser does not control the operation

of the supply source but would be responsible for payment of the persistent undergeneration or performance charge;

15.3A.2.2 Existing topping turbine Generators and extraction turbine Generators producing electric Energy resulting from the supply of steam to the district steam system in operation on or before November 18, 1999 and/or Generators utilized in replacing or repowering existing steam supplies from such units (in accordance with good engineering and economic design) that cannot follow schedules, up to a maximum total of 533 MW of such units;

15.3A.2.3 Limited Control Run of River Hydro Resources;

15.3A.2.4 Intermittent Power Resources and Aggregations of Intermittent Power Resources that depend on landfill gas as their fuel;

15.3A.2.5 Intermittent Power Resources and Aggregations of Intermittent Power Resources that depend on wind or solar energy as their fuel;

15.3A.2.6 Prior to the Capability Period beginning May 1, 2025, Capacity Limited Resources, Aggregations of Capacity Limited Resources, Energy Limited Resources and Aggregations of Capacity Limited Resources, to the extent that their real-time Energy injections are equal to or greater than their bid-in upper operating limits but are less than their Real-Time Scheduled Energy Injections. Beginning with the Capability Period beginning May 1, 2025, Energy Limited Resources to the extent that their real-time Energy injections are equal to or greater than their bid-in upper operating limits but are less than their Real-Time Scheduled Energy Injections;

15.3A.2.7 Generators operating in their Start-Up Period or their Shutdown Period and, for Generators comprised of a group of generating units at a single location, which grouped generating units are separately committed and dispatched by the ISO, and for which Energy injections are measured at a single location, each of the grouped generating units when one of the grouped generating units is operating in its Start-Up or Shutdown Period; and

15.3A.2.8 Generators operating during a Testing Period.

15.3A.2.9 Energy Storage Resources with schedules to withdraw Energy are instead subject to persistent over-withdrawal charges.

For Generators and Resources described in Sections 15.3A.2.1, 15.3A.2.2, 15.3A.2.3, and 15.3A.2.4 above, this exemption shall not apply in an hour if the Generator or Resource has bid in that hour as ISO-Committed Flexible or Self-Committed Flexible.

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 and quality of Operating Reserves to comply with the Reliability Rules, applicable reliability standards, and the rules set forth in this Rate Schedule, as further defined in ISO Procedures. In addition, Operating Reserve requirements shall satisfy Uncertainty Reserve Requirements and Scarcity Reserve Requirements, as applicable. These quantities shall be established under Section 15.4.7 of this Rate Schedule for locational Operating Reserve requirements, including Uncertainty 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.

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. The ISO may schedule a Combined Cycle Gas Turbine Generator with Duct-Firing Capability that has opted for the Limiting Participation Flag, which is 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 Participation Limit; and (ii) 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 UOLN or UOLE, 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 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 is scheduled to provide, shall account for the CSR withdrawal Scheduling Limit consistent with ISO Procedures.

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). The ISO may schedule a Combined Cycle Gas Turbine Generator with Duct-Firing Capability that has opted for the Limiting Participation Flag, which is 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 Participation Limit; and (ii) 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, that each Resource is scheduled to provide, the amount of Regulation Service it is scheduled to provide, and the amount of each Operating Reserves product it is scheduled to provide shall not exceed its UOL_N or UOL_E, whichever is applicable.

For an Energy Storage Resource 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.

Suppliers will thus be selected on the basis of their response rates, their applicable upper operating limits, and their Energy Bids (which will reflect their opportunity costs) through a co-optimized real-time commitment process that minimizes the total bid cost of Energy, 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. 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).

Uncertainty Reserve Requirements are Operating Reserves needed to account for the uncertainty associated with Load forecasts and Wind and Solar Energy Forecasts. Uncertainty Reserve Requirements shall be calculated for, and apply to, both the Day-Ahead and Real-Time Market; in each market, the Uncertainty Reserve Requirements shall be calculated with the objective of ensuring that there is a 95 percent probability that uncertainty reserves will be sufficient to offset the net effect of uncertainty in these forecasts on the amount of Load to be served net of output by wind and solar resources Uncertainty Reserve Requirements shall be calculated prior to each operating day using (1) historical measured forecast error and (2) forecasts of Load and Wind and Solar Energy Forecasts for that Operating Day. In the Day-

Ahead Market, the Uncertainty Reserves Requirement will only be included in the calculation of the 30-Minute Reserve requirement for each location with such a requirement. In the Real-Time Market, the Uncertainty Reserves Requirement will be included in the calculation of 10-Minute Reserve and 30-Minute Reserve requirements.

Uncertainty Reserve Requirements for the Day-Ahead Market for each location are calculated for each hour of the Dispatch Day before the Day-Ahead Market run. Day-Ahead Uncertainty Reserve Requirements are a function of an annually determined NYCA Day-Ahead forecast error metrics and Day-Ahead Market forecast data for the relevant location.

The quantities that Uncertainty Reserve Requirements contribute to 10-Minute Reserve requirements and 30-Minute Reserve requirements in the Real-Time Market are calculated for the entire Dispatch Day for each location with a 10-Minute Reserve or a 30-Minute Reserve requirement. In the Real-Time Market, the contribution of Uncertainty Reserve Requirements to the 30-Minute Reserve requirements is a function of an annually determined NYCA 60-minute ahead forecast error metrics and the Day-Ahead Market forecast data for the relevant location before the Day-Ahead Market run. In the Real-Time Market, the contribution of Uncertainty Reserve Requirements to the 10-Minute Reserve requirements is a function of an annually determined NYCA 30-minute ahead forecast error metrics and the Day-Ahead Market forecast data for the relevant location before the Day-Ahead Market run.

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. The following locational Operating Reserves requirements shall each include an Uncertainty Reserve Requirement: (i) Total 10-Minute Reserves; (ii) Eastern, Southeastern, New York City, or Long Island 10-Minute Reserves; (iii) New York City 10-Minute Reserves; (iv) Long Island 10-Minute Reserves; (v) Total 30-Minute Reserves; (vi) 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); (viii) Southeastern, New York City, or Long Island 30-Minute Reserves; (ix) New York City 30-Minute Reserves; and (x) Long Island 30-Minute Reserves. 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 (referred to as the "NYCA 10-Minute Reserves target level"), that are less than or equal to the NYCA 10-Minute Reserves target level minus the total 10-Minute Uncertainty Reserve Requirement, the price on the total 10-minute reserves demand curve shall be $750/MW. For quantities of Operating Reserves meeting the NYCA 10-Minute Reserves target level that (i) are less than or equal to the NYCA 10-Minute Reserves target level, but (ii) exceed the NYCA 10-Minute Minute Reserves target level minus the total 10-Minute Uncertainty Reserves Requirement, the price on the total 10-minute reserves demand curve shall be $40/MWh. 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 (referred to as the "Eastern, Southeastern, New York City, or Long Island 10-Minute Reserves target level"), that are less than or equal to the Eastern, Southeastern, New York City, or Long Island 10-Minute Reserves target level minus the Eastern, Southeastern, New York City, or Long Island 10-Minute Uncertainty Reserve Requirement, the price on the Eastern, Southeastern, New York City, or Long Island 10-minute reserves demand curve shall be $775/MW. For quantities of Operating Reserves meeting the Eastern, Southeastern, New York City, or Long Island 10-Minute Reserves target level that (i) are less than or equal to the Eastern, Southeastern, New York City, or Long Island 10-Minute Reserves target level, but (ii) exceed the Eastern, Southeastern, New York City, or Long Island 10-Minute Operating Reserve target level minus the Eastern, Southeastern, New York City, or Long Island 10-Minute Uncertainty Reserves Requirement, the price on the Eastern, Southeastern, New York City, or Long Island 10-minute reserves demand curve shall be $40/MWh. 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 (referred to as the "N.Y.C. 10-Minute Reserves target level"), that are less than or equal to the N.Y.C. 10-Minute Reserves target level minus the N.Y.C. 10-Minute Uncertainty Reserve Requirement, the price on the New York City 10-minute reserves demand curve shall be $25/MW. For quantities of Operating Reserves meeting the N.Y.C. 10-Minute Reserves target level that (i) are less than or equal to the N.Y.C. 10-Minute Reserves target level, but (ii) exceed the N.Y.C. 10-Minute Operating Reserve target level minus the N.Y.C. 10-Minute Uncertainty Reserve Requirement, the price on the New York City 10-minute reserves demand curve shall be $20/MWh. 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 (referred to as the "Long Island 10-Minute Reserves target level"), that are less than or equal to the Long Island 10-Minute Reserves target level minus the Long Island 10-Minute Uncertainty Reserve Requirement, the price on the Long Island 10-minute reserves demand curve shall be $25/MW. For quantities of Operating Reserves meeting the Long Island 10-Minute Reserves target level that (i) are less than or equal to the Long Island 10-Minute Reserves target level, but (ii) exceed the Long Island 10-Minute Operating Reserves target level minus the Long Island 10-Minute Uncertainty Reserve Requirement, the price on the Long Island 10-minute reserves demand

curve shall be $20/MWh. 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 (referred to as the "NYCA 30-Minute Reserves target level") that are less than or equal to the NYCA 30-Minute Reserves target level minus an amount equal to the sum of 655 MW and the total 30-Minute Uncertainty Reserve Requirement, the price on the total 30-Minute Reserves demand curve shall be $750/MW. For quantities of Operating Reserves meeting the NYCA 30-Minute Reserves target level that (i) are less than or equal to the NYCA 30-Minute Reserves target level minus an amount equal to the sum of 600 MW and the total 30-Minute Uncertainty Reserve Requirement, but (ii) exceed the NYCA 30-Minute Reserves target level minus an amount equal to the sum of 655 MW and the total 30-Minute Uncertainty Reserve Requirement, the price on the total 30-Minute Reserves demand curve shall be $625/MW. For quantities of Operating Reserves meeting the NYCA 30-Minute Reserves target level that (i) are less than or equal to the NYCA 30-Minute Reserves target level minus an amount equal to the sum of 545 MW and the total 30-Minute Uncertainty Reserve Requirement, but (ii) exceed the NYCA 30-Minute Reserves target level minus an amount equal to the sum of 600 MW and the total 30-Minute Uncertainty Reserve Requirement, the price on the total 30-Minute Reserves demand curve shall be $500/MW. For quantities of Operating Reserves meeting the NYCA 30-Minute Reserves target level that (i) are less than or equal to the NYCA 30-Minute Reserves target level minus an amount equal to the sum of 490 MW and the total

30-Minute Uncertainty Reserve Requirement, but (ii) exceed the NYCA 30-Minute Reserves target level minus an amount equal to the sum of 545 MW and the total 30-Minute Uncertainty Reserve Requirement, the price on the total 30-Minute Reserves demand curve shall be $375/MW. For quantities of Operating Reserves meeting the NYCA 30-Minute Reserves target level that (i) are less than or equal to the NYCA 30-Minute Reserves target level minus an amount equal to the sum of 435 MW and the total 30-Minute Uncertainty Reserve Requirement, but (ii) exceed the NYCA 30-Minute Reserves target level minus an amount equal to the sum of 490 MW and the total 30-Minute Uncertainty Reserve Requirement, the price on the total 30-Minute Reserves demand curve shall be $300/MW. For quantities of Operating Reserves meeting the NYCA 30-Minute Reserves target level that (i) are less than or equal to the NYCA 30-Minute Reserves target level minus an amount equal to the sum of 380 MW and the total 30-Minute Uncertainty Reserve Requirement, but (ii) exceed the NYCA 30-Minute Reserves target level minus an amount equal to the sum of 435 MW and the total 30-Minute Uncertainty Reserve Requirement, the price on the total 30-Minute Reserves demand curve shall be $225/MW. For quantities of Operating Reserves meeting the NYCA 30-Minute Reserves target level that (i) are less than or equal to the NYCA 30-Minute Reserves target level minus an amount equal to the sum of 325 MW and the total 30-Minute Uncertainty Reserve Requirement, but (ii) exceed the NYCA 30-Minute Reserves target level minus an amount equal to the sum of 380 MW and the total 30-Minute Uncertainty Reserve Requirement, the price on the total 30-Minute Reserves demand curve shall be $175/MW. For

quantities of Operating Reserves meeting the NYCA 30-Minute Reserves target level that (i) are less than or equal to the NYCA 30-Minute Reserves target level minus an amount equal to the sum of 200 MW and the total 30-Minute Uncertainty Reserve Requirement, but (ii) exceed the NYCA 30-Minute Reserves target level minus an amount equal to the sum of 325 MW and the total 30-Minute Uncertainty Reserve Requirement, the price on the total 30-Minute Reserves demand curve shall be $100/MW. For quantities of Operating Reserves meeting the NYCA 30-Minute Reserves target level that (i) are less than or equal to the NYCA 30-Minute Reserves target level minus an amount equal to the total 30-Minute Uncertainty Reserve Requirement, but (ii) exceed the NYCA 30-Minute Reserves target level minus an amount equal to the sum of 200 MW and the total 30-Minute Uncertainty Reserve Requirement, the price on the total 30-Minute Reserves demand curve shall be $40/MW. For quantities of Operating Reserves meeting the NYCA 30-Minute Reserves target level that (i) are less than or equal to the NYCA 30-Minute Reserves target level, but (ii) exceed the NYCA 30-Minute Operating Reserve target level minus the total NYCA 30-Minute Uncertainty Reserve Requirement, the price on the total 30-Minute Reserves demand curve shall be $20/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 NYCA 30-Minute Reserves target level plus the greater of (i) the value obtained from subtracting the total 30-Minute Uncertainty Reserve Requirement from the Scarcity Reserve Requirement, or (ii) zero ("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 greater of (i) the Scarcity Reserve Requirement, or (ii) the total 30-Minute Uncertainty 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 greater of the Scarcity Reserve Requirement or the total 30-Minute Uncertainty Reserve Requirement, but (ii) exceed the NYCA scarcity target level minus an amount equal to the sum of 655 MW and the greater of the Scarcity Reserve Requirement or the total 30-Minute Uncertainty 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 minus an amount equal to the greater of (a) zero or (b) a value obtained from subtracting the Scarcity Reserve Requirement from the total 30-Minute Uncertainty Reserve Requirement but (ii) exceed the NYCA scarcity target level minus an amount equal to the sum of 600 MW and the greater of the Scarcity Reserve Requirement or the total 30-Minute

Uncertainty Reserve Requirement, the price on the total 30-Minute Reserves demand curve shall be $500/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, but (ii) exceed the NYCA scarcity target level minus an amount equal to the greater of (a) zero or (b) a value obtained from subtracting the Scarcity Reserve Requirement from the total 30-Minute Uncertainty Reserve Requirement, the price on the total 30-Minute Reserves demand curve shall be $20/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 NYCA 30-Minute Reserves target level plus the greater of (i) the value obtained from subtracting the total 30-Minute Uncertainty Reserve Requirement from the applicable Scarcity Reserve Requirement(s), or (ii) zero ("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 greater of (a) the Scarcity Reserve Requirement(s), or (b) the total 30-Minute Uncertainty Reserve Requirement, 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 greater of the Scarcity Reserve Requirement(s) or the total 30-Minute Uncertainty Reserve Requirement, but (ii) exceed the adjusted NYCA target level minus an amount equal to the sum of 655 MW and the greater of the Scarcity Reserve Requirement(s) or the total 30-Minute Uncertainty Reserve Requirement, 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 minus an amount equal to the greater of (a) zero, or (b) a value obtained from subtracting the Scarcity Reserve Requirement(s) from the total 30-Minute Uncertainty Reserve Requirement, but (ii) exceed the adjusted NYCA target level minus an amount equal to the sum of 600 MW and the greater of the Scarcity Reserve Requirement(s), or the total 30-Minute Uncertainty Reserve Requirement, the price on the total 30-Minute Reserves demand curve shall be $500/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 greater of (i) zero, or (ii) a value obtained from subtracting the Scarcity Reserve Requirement(s) from the total 30-Minute Uncertainty Reserve Requirement, the price on the total 30-Minute Reserves demand curve shall be $20/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 (referred to as the "Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves target level"), that are less than or equal to the Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves target level minus the Eastern, Southeastern, New York City, or Long Island 30-Minute Uncertainty Reserve Requirement, the price on the Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be $40/MW. For quantities of Operating Reserves meeting the Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves target level that (i) are less than or equal to the Eastern 30-Minute Reserves target level, but (ii) exceed the Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves target level minus the Eastern, Southeastern, New York City, or Long Island 30-Minute Uncertainty Reserve Requirement, the price on the Eastern, Southeastern, New York City, or Long Island 30-minute reserves demand curve shall be $20/MWh. 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 target level plus the greater of (i) the value obtained from subtracting the Eastern, Southeastern, New York, or Long Island 30-Minute Uncertainty Reserve Requirement from the Scarcity Reserve Requirement, or (ii) zero ("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 target level, 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 minus an amount equal to the greater of (a) zero, or (b) a value obtained from subtracting the Scarcity Reserve Requirement from the Eastern, Southeastern, New York City, or Long Island 30-Minute Uncertainty Reserve Requirement 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 target level, the price on the Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be $40/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 greater of (a) zero, or (b) a value obtained from subtracting the Scarcity Reserve Requirement from the Eastern, Southeastern,

New York City, or Long Island 30-Minute Uncertainty Reserve Requirement, the price on the Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be $20/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 target level plus the greater of (i) the value obtained from subtracting the Eastern, Southeastern, New York City, or Long Island 30-Minute Uncertainty Reserve from the applicable Scarcity Reserve Requirement(s), or (ii) zero (“adjusted Eastern target level”) that are less than or equal to the adjusted Eastern target level minus the Eastern, Southeastern, New York City, or Long Island 30-Minute Uncertainty Reserve Requirement, the price on the Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be $40/MW. For quantities of Operating Reserves meeting the adjusted Eastern target level that (i) are less than or equal to the adjusted Eastern target level, but (ii) exceed the adjusted Eastern target level minus the

Eastern, Southeastern, New York City, or Long Island 30-Minute Uncertainty Reserve Requirement, the price on the Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be $20/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 (referred to as the "Southeastern, New York City, or Long Island 30-Minute Reserves target level"), that are less than or equal to the Southeastern, New York City, or Long Island 30-Minute Reserves target level minus the sum of the Southeastern, New York City, or Long Island 30-minute Uncertainty Reserve Requirement and 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 target level that (i) are less than or equal to the Southeastern, New York City, or Long Island 30-Minute Reserves target level minus the Southeastern, New York City, or Long Island 30-Minute Uncertainty Reserve Requirement, but (ii) exceed the Southeastern, New York City, or Long Island 30-Minute Uncertainty Reserve Requirement minus the sum of the Southeastern, New York City, or Long Island 30-Minute Uncertainty Reserve Requirement and 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 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 Southeastern, New York City, or Long Island 30-Minute Reserves target level, but (ii) exceed the Southeastern, New York City, or Long Island 30-Minute Reserves target level minus the Southeastern 30-Minute Uncertainty Reserve Requirement, the price on the Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be $20/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 target level plus the greater of (i) the value obtained from subtracting the Southeastern, New York City, or Long Island 30-Minute Uncertainty Reserve Requirement from the Scarcity Reserve Requirement, or (ii) zero ("Southeastern scarcity target level") that are less than or equal to the Southeastern scarcity target level minus a value equal to the sum of the SENY incremental reserve target level and the greater of (i) zero or (ii) the value obtained from subtracting the Scarcity Reserve Requirement from the Southeastern, New York City or Long Island 30-

Minute Uncertainty Reserve Requirement, 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 minus an amount equal to the greater of (a) zero or (b) a value obtained from subtracting the Scarcity Reserve Requirement from the Southeastern, New York City, or Long Island 30-Minute Uncertainty Reserve Requirement, but (ii) exceed the Southeastern scarcity target level minus a value equal to the sum of the SENY incremental reserve target level and the greater of (a) zero or (b) the value obtained from subtracting the Scarcity Reserve Requirement from the Southeastern, New York City or Long Island 30-Minute Uncertainty Reserve Requirement, the price on the Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be $40/MW. For the 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 an amount equal to the greater of (a) zero or (b) a value obtained from subtracting the Scarcity Reserve Requirement from the Southeastern, New York City, or Long Island 30-Minute Uncertainty Reserve Requirement, the price on the Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be $20/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 target level plus the greater of (i) the value obtained from subtracting the Southeastern, New York City, or Long Island 30-Minute Uncertainty Reserve Requirement from the applicable Scarcity Reserve Requirement(s) or (ii) zero ("adjusted Southeastern target level") that are less than or equal to the adjusted Southeastern target level minus a value equal to the sum of the SENY incremental reserve target level and the greater of (a) zero or (b) the value obtained from subtracting the Scarcity Reserve Requirement from the Southeastern, New York City or Long Island 30-Minute Uncertainty Reserve Requirement, 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 minus an amount equal to the greater of (a) zero or (b) a value obtained from subtracting the Scarcity Reserve Requirement from the Southeastern, New York City, or Long Island 30-Minute Uncertainty Reserve Requirement, but (ii) exceed the adjusted Southeastern target

level minus a value equal to the sum of the SENY incremental reserve target level and the greater of (a) zero or (b) the value obtained from subtracting the Scarcity Reserve Requirement from the Southeastern, New York City or Long Island 30-Minute Uncertainty Reserve Requirement, the price on the Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be $40/MW. For the 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 an amount equal to the greater of (a) zero or (b) a value obtained from subtracting the Scarcity Reserve Requirement from the Southeastern, New York City, or Long Island 30-Minute Uncertainty Reserve Requirement, the price on the Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be $20/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 (referred to as the "N.Y.C. 30-Minute Reserves target level"), that are less than or equal to the N.Y.C. 30-Minute Reserves target level minus the N.Y.C. 30-minute Uncertainty Reserve Requirement, the price on the New York City 30-Minute Reserves demand curve shall be $25/MW. For quantities of Operating Reserves meeting the N.Y.C. 30-Minute Reserves target level that (i) are less than or equal to the N.Y.C. 30-Minute Reserves target level, but (ii) exceed the N.Y.C. 30-Minute Operating Reserves target level minus the N.Y.C. 30-Minute Uncertainty

Reserves Requirement, the price on the New York City 30-minute reserves demand curve shall be $20/MWh. 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 target level plus the greater of (i) the value obtained from subtracting the New York City 30-Minute Uncertainty Reserve Requirement from the Scarcity Reserve Requirement or (ii) zero ("N.Y.C. scarcity target level") that are less than or equal to the N.Y.C. scarcity target level minus a value equal to the sum of the N.Y.C. 30-Minute Reserves target level and the greater of (i) zero or (ii) the value obtained from subtracting the Scarcity Reserve Requirement from the New York City 30-Minute Uncertainty Reserve Requirement, 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 minus an amount equal to the greater of (i) zero or (ii) a value obtained from subtracting the Scarcity Reserve Requirement from the N.Y.C. 30-Minute Uncertainty Reserve Requirement, but (ii) exceed the N.Y.C. scarcity target level minus a value equal to the sum of the N.Y.C. 30-Minute Reserves target level and the greater of (a) zero or (b) the value obtained from subtracting the Scarcity Reserve Requirement

from the New York City 30-Minute Uncertainty Reserve Requirement, the price on the New York City 30-Minute Reserves demand curve shall be $25/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 greater of (i) zero or (ii) a value obtained from subtracting the Scarcity Reserve Requirement from the N.Y.C. 30-Minute Uncertainty Reserve Requirement, the price on the New York City 30-Minute Reserves demand curve shall be $20/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 (referred to as the "Long Island 30-Minute Reserves target level"), that are less than or equal to the Long Island 30-Minute Reserves target level for that locational requirement minus the Long Island 30-minute Uncertainty Reserve Requirement, the price on the Long Island 30-Minute Reserves demand curve shall be $25/MW. For quantities of Operating Reserves meeting the Long Island 30-Minute Reserves target level that (i) are less than or equal to the Long Island 30-Minute Reserves target level, but (ii) exceed the Long Island 30-Minute Operating Reserves target level minus the Long Island 30-Minute Uncertainty Reserves Requirement, the price on the Long Island 30-minute reserves demand curve shall be $20/MWh. 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 target level plus the greater of (i) the value obtained from subtracting the Long Island 30-Minute Uncertainty Reserve Requirement from the Scarcity Reserve Requirement or (ii) zero ("Long Island scarcity target level") that are less than or equal to the Long Island scarcity target level minus a value equal to the sum of the Long Island 30-Minute Reserves target level and the greater of (i) zero or (ii) the value obtained from subtracting the Scarcity Reserve Requirement from the Long Island 30-Minute Uncertainty Reserve Requirement, 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 minus an amount equal to the greater of (i) zero or (ii) a value obtained from subtracting the Scarcity Reserve Requirement from the Long Island 30-Minute Uncertainty Reserve Requirement, but (ii) exceed the Long Island scarcity target level minus a value equal to the sum of the Long Island 30-Minute Reserves target level and the greater of (a) zero or (b) the value obtained from subtracting the Scarcity Reserve Requirement from the Long Island 30-Minute Uncertainty Reserve Requirement, the price on the Long Island 30-Minute Reserves demand curve shall be $25/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 greater of (i) zero or (ii) a value obtained from subtracting the Scarcity Reserve Requirement from the Long Island 30-Minute Uncertainty Reserve Requirement, the price on the Long Island 30-Minute Reserves demand curve shall be $20/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.

15.5 Rate Schedule 5 - Payments and Charges for Black Start and System Restoration Services

Black start and system restoration services ("Restoration Services") are provided under the ISO's black start and system restoration plan ("ISO Plan") or an individual Transmission Owner's black start and system restoration plan for its Transmission District by generating units that are capable of starting without an outside electrical supply or are otherwise integral to the restoration of the NYS Transmission System after an outage. This Rate Schedule establishes the terms under which a Generator shall provide, and be paid by the ISO for providing, Restoration Services under the ISO Plan or an individual Transmission Owner's plan for its Transmission District. This Rate Schedule also establishes the terms under which the ISO shall recover the costs of Restoration Services payments from Customers. Provisions specific to the Consolidated Edison Company of New York, Inc. ("Consolidated Edison") black start and system restoration plan ("Consolidated Edison Plan") are set forth in Section 15.5.4.

15.5.1 Requirements

The ISO shall develop and periodically review the ISO Plan. The ISO may amend the ISO Plan and may solicit offers for additional resources if it determines that additional Restoration Services are needed. The ISO shall establish procedures for acquiring Restoration Services and requiring that the selected Generators test their units providing Restoration Services ("Black Start Capability Test"). The ISO shall make Restoration Services payments only to those selected Generators that have appropriate equipment installed and available for service at the request of the ISO.

A Transmission Owner with a Transmission District shall develop and periodically review its black start and system restoration plan. Such Transmission Owner shall designate

generating units with the capability to provide Restoration Services to be included in its plan if it determines that the Restoration Services are needed. The ISO will make payments for such local Restoration Services to the Generators that provide them under the terms of this Rate Schedule. Generators that are obligated to provide Restoration Services as a result of divestiture contract agreements will not receive Restoration Services payments from the ISO for those services if they are already compensated as part of those divestiture contracts. Customers in the local Transmission Owner service territories will be charged for those services by the ISO under the terms of this Rate Schedule. Customers may not Self-Supply Restoration Services.

15.5.2 Payments to Generators for Provision of Restoration Services Under the ISO Plan and Transmission Owners' Plans, Excluding the Consolidated Edison Plan

By May 1st of each year, Generators selected to provide Restoration Services under the ISO Plan and under the plans developed by individual Transmission Owners with a Transmission District, except for under the Consolidated Edison Plan, must provide the following cost information to the ISO based upon FERC Form No. 1 or equivalent data:

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

Each Billing Period, the ISO shall pay each Generator on the basis of its costs filed with the ISO. The daily rate for Restoration Services payments will be determined by dividing the Generator's annual cost by the number of days in the year from May 1st through April 30th of the following year.

Generators that provide Restoration Services shall conduct Black Start Capability Tests that are deemed necessary and appropriate for providers of these services under the ISO

Procedures or local Transmission Owner procedures, as applicable. Any Generator that is awarded Restoration Services payments and fails a Black Start Capability Test shall forfeit all payments for such services since its last successful test. Payments to that Generator shall resume upon its successful completion of the test.

15.5.3 Charges to Support Payments to Generators Under the ISO Plan and Individual Transmission Owners' Plans, Excluding the Consolidated Edison Plan.

Each Billing Period, the ISO shall charge, and each Customer shall pay based on its supply of Load that is *not* used to supply Station Power as a third-party provider under Part 5 of the ISO OATT, a charge for the recovery of the costs of the ISO's payments to Generators providing Restoration Services under the ISO Plan. The charge shall be equal to: (A) the product of: (i) the Customer's share of Load in the NYCA that is *not* used to supply Station Power as a third-party provider for each hour in the Billing Period, and (ii) the ISO's total payments to Generators providing Restoration Services under the ISO Plan under Section 15.5.2 to this Rate Schedule for the Billing Period, divided by the total number of hours in the Billing Period, (B) summed for all hours in the Billing Period.

Each Billing Period, the ISO shall charge, and each Customer shall pay based on its supply of Load that is used to supply Station Power as a third-party provider under Part 5 of the ISO OATT, a charge for the recovery of the costs of the ISO's payments to Generators providing Restoration Services under the ISO Plan. The charge shall be equal to: (A) the product of: (i) the Customer's share of Load in the NYCA that is used to supply Station Power as a third-party provider for each day in the Billing Period, and (ii) the ISO's total payments to Generators providing Restoration Services under the ISO Plan under Section 15.5.2 to this Rate Schedule for the Billing Period, divided by the total number of days in the Billing Period, (B) summed for all

days in the Billing Period. The ISO shall credit these daily charge amounts to Customers based on their share of the Load in the NYCA that is not used to supply Station Power as a third-party provider for that day. The ISO shall sum these daily credits for all days in the Billing Period.

A Customer will be responsible for the following additional charge if the Transmission Owner in whose Transmission District the Customer is located maintains a Restoration Services plan, except with respect to the Consolidated Edison Plan, the cost recovery requirements of which are set forth in Section 15.5.4.2 to this Rate Schedule. Each Billing Period, the ISO shall charge, and each Customer in the local Transmission Owner's Transmission District shall pay, a charge for the recovery of the costs of the ISO's payments to Generators providing Restoration Services under the Transmission Owner's local Restoration Services plan. This charge shall be equal to: (A) the product of: (i) the Customer's share of Load in the Transmission Owner's Transmission District for each hour in the Billing Period, and (ii) the ISO's total payments to Generators providing Restoration Services under the Transmission Owner's Restoration Services plan under Section 15.5.2 to this Rate Schedule for the Billing Period, divided by the total number of hours in the Billing Period, (B) summed for all hours in the Billing Period.

15.5.4 Payments to Generators Providing Restoration Services Under the Consolidated Edison Plan and Recovery of Associated Costs

A Generator that provides Restoration Services under the Consolidated Edison Plan shall provide, and be paid for providing, Restoration Services under the terms set forth in Section 15.5.4.1 and Appendix I to this Rate Schedule. If Consolidated Edison determines that additional Restoration Services are needed, it may from time to time designate for inclusion in the Consolidated Edison Plan: (i) an existing generating unit that is capable of providing Restoration Services but that is not currently doing so, or (ii) a generating unit for which the

Generator has provided notice to withdraw from the Consolidated Edison Plan pursuant to Section 15.5.4.1.1. A generating unit designated by Consolidated Edison may elect to participate in the Consolidated Edison Plan; otherwise it shall be required to participate in the Consolidated Edison Plan unless the ISO determines that: (i) the generating unit would not provide a material benefit to system restoration in Zone J, or (ii) the Generator shows good cause that it would be unduly burdensome or unreasonable to require it to provide Restoration Services from the designated generating unit.

The provision of Restoration Services will be deemed to provide a material benefit to system restoration in Zone J if, among other things, it would materially improve the speed, adequacy, or flexibility of the Consolidated Edison Plan for restoring electric service in Zone J in a safe, orderly, and prompt manner following a major system disturbance.

To facilitate the ISO's determination regarding material benefit, Consolidated Edison shall provide a study and/or other documentation, performed at its own expense, supporting the conclusion that the designated generating unit would provide a material benefit for system restoration in Zone J. Consolidated Edison's documentation must: (i) include its assessment of the adequacy of resources already committed to provide Restoration Services under the Consolidated Edison Plan and the need for additional resources, (ii) describe the manner in which the designated generating unit would provide a material benefit for system restoration in Zone J, and (iii) summarize alternative solutions evaluated, if applicable, and indicate whether other generating units would provide the particular material benefit identified. Consolidated Edison shall provide its documentation to the ISO and the relevant Generator, subject to appropriate confidentiality protections. Upon request, Consolidated Edison shall provide the

documentation to other parties that have a direct interest in this matter, subject to appropriate confidentiality protections.

If the Generator asserts that good cause exists for not requiring its generating unit to participate in the Consolidated Edison Plan, it must seek an exemption from the ISO. The Generator shall provide a study or other documentation demonstrating the engineering, technical, financial, environmental, and/or other reasons that provision or continued provision of Restoration Services by the designated generating unit would be unduly burdensome or unreasonable. The Generator shall provide its documentation to the ISO and Consolidated Edison, subject to appropriate confidentiality protections. The Generator may provide the documentation to other parties that have a direct interest in this matter as well, subject to appropriate confidentiality protections. In making its determination, the ISO may rely on the supporting documentation provided by the Generator and Consolidated Edison, along with any information developed by the ISO.

If the ISO determines that good cause exists to grant a requested exemption, the designated generating unit will not be required to participate in the Consolidated Edison Plan. Otherwise, the designated generating unit will be required to participate in the Consolidated Edison Plan and will be assigned by the ISO to a Commitment Group under Section 15.5.4.1.1. The ISO shall inform NYSRC of a designated generating unit's request for an exemption and the ISO's determination under this Section 15.5.4.

A Generator's unit that is designated by Consolidated Edison to participate in the Consolidated Edison Plan, and is not granted an exemption under this Section 15.5.4 shall provide, and be paid for providing, Restoration Services under the terms set forth in Section 15.5.4.1 and Appendix I to this Rate Schedule.

The ISO shall recover the costs of the payments established in Section 15.5.4.1 from Customers in the Consolidated Edison Transmission District under the terms set forth in Section 15.5.4.2.

Within thirty (30) days of receipt of an updated Consolidated Edison Plan, including changes to unit designations as described in this section, the ISO will file a copy with FERC on an informational basis with a non-public Critical Energy Infrastructure Information designation.

15.5.4.1 Payments to Generators that Provide Restoration Services Under the Consolidated Edison Plan

15.5.4.1.1 Commitment Requirements for Restoration Services

Each generating unit committed to provide Restoration Services under the Consolidated Edison Plan before November 1, 2012, was included in one of three groups ("Commitment Groups") with the following initial commitment periods:

Commitment Group 1: November 1, 2012, through April 30, 2015.

Commitment Group 2: November 1, 2012, through April 30, 2016.

Commitment Group 3: November 1, 2012, through April 30, 2017.

The ISO shall assign a generating unit subsequently designated to provide Restoration Services under the Consolidated Edison Plan to one of these Commitment Groups.

At the conclusion of each commitment period, a generating unit shall begin a new three (3) year commitment period to provide Restoration Services under the Consolidated Edison Plan; provided, however, that the unit shall not begin a new commitment period if the Generator or Consolidated Edison provides the ISO with notice at least two years prior to the conclusion of the previous commitment period that the unit will no longer be part of the Consolidated Edison Plan following the conclusion of that commitment period.

Notwithstanding the foregoing, a unit previously designated under Section 15.5.4 shall be required to begin a new commitment period if: (i) Consolidated Edison provides the ISO and the Generator with notice at least one year prior to the conclusion of the previous commitment period that the unit continues to be required to provide a material benefit to system restoration in Zone J, (ii) and the ISO determines that the unit should continue to provide service in accordance with the designation requirements in Section 15.5.4, including the opportunity for the Generator to request an exemption.

Consolidated Edison shall not remove from the Consolidated Edison Plan a new or repowered unit that was required to provide Restoration Services in the Consolidated Edison Plan pursuant to, as applicable, Section 30.2.5 of Attachment X or Section 40.2.12 of Attachment HH to the ISO OATT before the Generator recovers the incremental capital costs it incurred in installing the Restoration Services capability for its unit. The Generator shall be deemed to have recovered these costs: (a) twenty-five years from the start of the unit's provision of Restoration Services if the Generator is taking payment pursuant to Section 15.5.4.1.3.1 to this Rate Schedule, or (b) over the period set forth in the Generator's unit-specific rate approved by FERC pursuant to Section 15.5.4.1.3.2 to this Rate Schedule. If a Generator withdraws its unit from the Consolidated Edison Plan before the completion of this time period, it will forfeit its entitlement to recover its incremental capital costs.

If a Generator withdraws a unit from the ISO's energy and capacity markets, the unit may cease its provision of Restoration Services at the same time without completing its commitment period. If the Generator returns the unit to the ISO's energy and capacity markets within three years of its withdrawal, the unit shall be required to provide Restoration Services for that portion of its commitment period that it had not completed.

15.5.4.1.2 Generator Testing and Training Requirements

A Generator shall conduct an annual Black Start Capability Test of each unit committed to provide Restoration Services under the Consolidated Edison Plan in accordance with the test protocols required by the Reliability Rules and applicable reliability standards and set forth in ISO Procedures. A Generator shall also identify its unit's critical Restoration Services equipment, maintain this equipment and perform tests to verify the condition of this critical equipment in accordance with good utility practice. Upon the performance of a Black Start Capability Test for its unit, the Generator shall submit a certification to the ISO each year – in the form provided in Appendix II to this Rate Schedule – indicating whether its unit has successfully completed its annual Black Start Capability Test and certifying that it maintains and tests the unit's critical Restoration Services equipment in accordance with good utility practice. The Generator shall also ensure that all appropriate personnel are trained in Restoration Services operations.

15.5.4.1.3 Payments to Generators for Providing Restoration Services Under the Consolidated Edison Plan

15.5.4.1.3.1 Standard Compensation

Except as set forth in Section 15.5.4.1.3.2 to this Rate Schedule, the ISO shall pay a Generator each Billing Period the pro rata share of the sum of the annual payment amounts for the provision of Restoration Services under the Consolidated Edison Plan at each of the Generator's facilities, as determined for each facility as follows.

The ISO shall calculate the annual Restoration Services payment amount for each Generator's facility for the compensation period of May 1 of each year through the following April 30; *provided, however*, the ISO shall recalculate the annual Restoration Services payment amount if, during the May 1 through April 30 compensation period, one of the Generator's units

withdraws from the Consolidated Edison Plan pursuant to Section 15.5.4.1.1 to this Rate Schedule or fails a Black Start Capability Test pursuant to Section 15.5.4.1.3.4 to this Rate Schedule.

The annual Restoration Services payment amount for each Generator's facility shall be equal to the sum of the annual payment amounts, calculated according to the following formula, for: (i) each unit at a Generator's facility providing Restoration Services under the Consolidated Edison Plan that is the sole user of equipment necessary to black start the unit and is not designated with other units as a group by the ISO ("Sole Black Start Unit"), and (ii) each group of units at the Generator's facility providing Restoration Services under the Consolidated Edison Plan that share the equipment necessary to black start the units or are otherwise designated as a group by the ISO ("Black Start Unit Group"). The ISO shall designate a Generator's unit as a Sole Black Start Unit or as part of a Black Start Unit Group at the start of the unit's commitment period, and this designation shall not be subject to change for the duration of the unit's commitment period.

$$RSPayment_{AnnBSU} = ActRSUnits_{BSU} \times \left(\frac{RSSlCap_{Ann} + RSSlO\&M_{Ann} + RSAddCap_{Ann} + RSAddO\&M_{Ann}}{DesRSUnits_{BSU}} \right)$$

Where:

BSU = The Sole Black Start Unit or the Black Start Unit Group.

$RSPayment_{AnnBSU}$ = The annual amount, in $, that the ISO shall pay a Generator for the Sole Black Start Unit or the Black Start Unit Group providing Restoration Services under the Consolidated Edison Plan.

$DesRSUnits_{BSU}$ = The number of units in the Sole Black Start Unit or the Black Start Unit Group designated by Consolidated Edison as participants in the Consolidated Edison Plan.

$ActRSUnits_{BSU}$ = The number of units in the Sole Black Start Units or the Black Start Unit Group actually participating in the Consolidated Edison Plan, which shall not include any unit designated by Consolidated Edison as a participant in the Consolidated Edison Plan that has withdrawn from the plan pursuant to Section 15.5.4.1.1 to this Rate Schedule or has failed a Black Start Capability Test pursuant to Section 15.5.4.1.3.4 to this Rate Schedule.

$RSSlCap_{Ann}$ = The station-level capital payment amount, in $, for the Sole Black Start Unit or for one unit of the Black Start Unit Group, as specified in the "Station-level" column of Table A, below, on the basis of that unit's size.

$RSSlO\&M_{Ann}$ = The station-level operating and maintenance amount, in $, for the Sole Black Start Unit or for one unit of the Black Start Unit Group, as specified in the "Station-level" column of Table B, below, on the basis of the unit's size.

$RSAddCap_{Ann}$ = The sum of the incremental capital payment amounts, in $, for the remaining units in the Black Start Unit Group, as specified in the "Additional Resource" column of Table A, below, on the basis of the remaining units' sizes.

$RSAddO\&M_{Ann}$ = The sum of the incremental operating and maintenance payment amounts, in $, for the remaining units in the Black Start Unit Group, as specified in the "Additional Resource" column in Table B, below, on the basis of the remaining units' sizes.

Table A - Restoration Services Capital Payments

Resource Type	Station-level Capital Payment	Additional Resource Capital Payment
MVA ≤ 10	$21,770	$10,880
10 < MVA ≤ 60	$214,570	$10,880
60 < MVA ≤ 90	$248,460	$10,880
90 < MVA ≤ 300, Small Starting Requirement	$414,980	$10,880
90 < MVA ≤ 300, Medium Starting Requirement	$957,920	$10,880
90 < MVA ≤ 300, Large Starting Requirement	$1,785,080	$10,880
300 < MVA, Large Starting Requirement	$1,833,750	$32,650

Table B - Restoration Services O&M Payments

Resource Type	Station-level O&M Payment	Additional Resource O&M Payment
MVA ≤ 10	$22,335	$6,040
10 < MVA ≤ 60	$42,295	$8,200
60 < MVA ≤ 90	$49,850	$10,140
90 < MVA ≤ 300, Small Starting Requirement	$118,255	$33,665
90 < MVA ≤ 300, Medium Starting Requirement	$252,265	$65,600
90 < MVA ≤ 300, Large Starting Requirement	$388,865	$65,820
300 < MVA, Large Starting Requirement	$414,540	$77,685

The figures in Tables A and B are determined as of 2011. The ISO shall adjust these figures annually using the "Gas Turbogenerators" subcategory of the "Other Production Plant" category of the Handy Whitman Index for the North Atlantic Region.

15.5.4.1.3.2 Unit-Specific Compensation

A Generator shall be entitled to recover through this ISO Services Tariff the actual, incremental cost of its unit's or units' provision of Restoration Services under the Consolidated Edison Plan. If the Generator determines that its actual, incremental cost of providing Restoration Services to the ISO from its unit(s) exceeds the payment amount determined under Section 15.5.4.1.3.1 to this Rate Schedule, the Generator shall submit to the ISO actual incremental cost documentation showing: (1) that the actual, incremental costs are reasonably and prudently incurred, (2) that the actual incremental costs are incurred solely for the purpose of providing Restoration Services, and (3) that the actual incremental costs exceed the payment amount determined under Section 15.5.4.1.3.1 to this Rate Schedule. Within thirty (30) days of receipt of all necessary documentation, or longer if the parties agree, the ISO will file at FERC, jointly with the Generator, the information provided by the Generator along with the proposed

tariff appendix. The Generator will retain the burden to show that its unit(s)-specific rate request meets the cost showing requirements outlined in this section. NYISO may subsequently comment on the substance of the proposed filing during the FERC noticed comment period. Upon approval by FERC, the Generator's unit(s)-specific rate shall be included as an appendix to this Rate Schedule. In such case, the ISO shall pay a Generator each Billing Period the pro rata share of the FERC-approved annual rate for its unit(s), except as set forth in Section 15.5.4.1.3.4 to this Rate Schedule. The ISO shall recover the costs of these payments from Customers in the Consolidated Edison Transmission District under Section 15.5.4.2 to this Rate Schedule.

15.5.4.1.3.3 Eligibility for Additional Cost Recovery

The ISO shall reimburse Generators for equipment damage if the ISO reasonably finds: (1) the damage resulted from operating such equipment in response to operational orders from the ISO, or Consolidated Edison, pursuant to the ISO Tariffs, (2) that reasonably available and customary insurance was not available for the damages incurred, and (3) the damage would not have occurred but for the Generator's provision of Restoration Services. The burden of making such showings shall be upon the Generator.

The payments for each Billing Period shall also include compensation for legitimate, verifiable, and adequately documented costs incurred solely as a result of a Generator's compliance with NERC critical infrastructure protection ("CIP") reliability standards applicable to the provision of Restoration Services, *i.e.*, a CIP cost that would not have been incurred if it were not providing Restoration Services. The Generator shall provide such invoices to the ISO, which will review and determine if compensation is appropriate.

15.5.4.1.3.4 Forfeiture of Payments As a Result of Failed Black Start Capability Tests

If a Generator's unit fails a Black Start Capability Test, the Generator shall forfeit all Restoration Service payments for that unit under Sections 15.5.4.1.3.1 and 15.5.4.1.3.2 from the date of the failed test; provided, however, that if the Generator's unit successfully completes the Black Start Capability Test within thirty days of the failed test, the Generator shall not forfeit its payments. This thirty-day period may be extended if agreed upon by the ISO, the Generator, and Consolidated Edison. If the Generator does not successfully complete its Black Start Capability Test within this thirty day, or extended, period and successfully completes the test at a later date, it shall receive its Restoration Services payments only from the date of the later, successful test going forward.

15.5.4.2 Charges to Support Payments to Generators Under the Consolidated Edison Plan

Each Billing Period, the ISO shall charge, and each Customer in the Consolidated Edison Transmission District shall pay based on its supply of Load in that Transmission District that is *not* used to supply Station Power as a third-party provider under Part 5 of the ISO OATT, a charge for the recovery of the ISO's payments to Generators providing Restoration Services under the Consolidated Edison Plan under Section 15.5.4.1 to this Rate Schedule. This charge shall be equal to: (A) the product of : (i) the Customer's share of Load in the Consolidated Edison Transmission District that is not used to supply Station Power as a third-party provided for each hour in the Billing Period, and (ii) the ISO's total payments to Generators for Restoration Services under the Consolidated Edison Restoration Plan under Sections 15.5.4.1 for the Billing Period, divided by the total number of hours in the Billing Period, (B) summed for all hours in the Billing Period.

Each Billing Period, the ISO shall charge, and each Customer in the Consolidated Edison Transmission District shall pay based on its supply of Load in that Transmission District that is used to supply Station Power as a third-party provider under Part 5 of the ISO OATT, a charge for the recovery of the ISO's payments to Generators providing Restoration Services under the Consolidated Edison Plan under Section 15.5.4.1 to this Rate Schedule. This charge shall be equal to: (A) the product of: (i) the Customer's share of Load in the Consolidated Edison Transmission District that is used to supply Station Power as a third-party provided for each day in the Billing Period, and (ii) the ISO's total payments to Generators for Restoration Services under the Consolidated Edison Restoration Plan under Section 15.5.4.1 for the Billing Period, divided by the total number of days in the Billing Period, (B) summed for all days in the Billing Period. The ISO shall credit these daily charge amounts to Customers based on their share of Load in the NYCA that is not used to supply Station Power as a third-party provider for that day. The ISO shall sum these daily credits for all days in the Billing Period.

Rate Schedule 5. Appendix I
Restoration Services Certification Form

[Name of Generator] hereby certifies that the **[name/location of unit]** performed a Black Start Capability Test on **[date]** and **[successfully completed/did not complete]** this test in accordance with the applicable ISO Procedures.

[Name of Generator] further certifies that it has identified a list of critical components in its units providing Restoration Services (e.g., batteries, diesel back-up generators, inverters etc.), maintains such critical components, and has performed tests to verify the condition of these critical components in accordance with good utility practice.

_____

Signature of Officer

15.6 Rate Schedule 6 - Quick Start Reserves

This Rate Schedule applies to the scheduling and payment mechanisms for Quick Start Reserves.

15.6.1 Qualification to Provide Quick Start Reserves

15.6.1.1 A Supplier may offer Quick Start Reserves from one or more blocks of generator units to the Transmission Owner to which the block of generator units is interconnected if the block of generator units is (i) qualified to provide 30-Minute Reserves, and (ii) capable of being set to Quick Start Mode.

15.6.1.2 A Supplier intending to offer Quick Start Reserves shall undertake a test scheduled pursuant to the ISO Procedures for Installed Capacity Suppliers qualifying to sell Installed Capacity in the NYCA to determine the DMNC of the Supplier's block of generator units. The Supplier shall, while undertaking the DMNC test in Quick Start Mode, make record of and notify, for information purposes, the Transmission Owner in the Supplier's Transmission District and the ISO of (i) the output level in MWs that the block of generator units produced at ten (10) minutes following start-up; and (ii) the output level in MWs that the block of generator units produced at fifteen (15) minutes following start-up. Delivery of this information to the Transmission Owner in the Supplier's Transmission District and the ISO shall constitute and be deemed to be a standing offer to provide Quick Start Reserves pursuant to Section 15.6.2 of this Rate Schedule until (i) the Supplier performs another DMNC test and provides the information required pursuant to this Section 15.6.1.2 to the ISO and the Transmission Owner, (ii) thirty (30) days after providing a notice to the ISO and

the Transmission Owner that it no longer offers Quick Start Reserves from any one or more blocks of generator units, provided that the supplier is not otherwise required to provide Quick Start Reserves, or (iii) the Supplier is not paid for Quick Start Reserves as provided herein.

15.6.1.3 A Supplier shall maintain each block of generator units for which Quick Start Reserves are offered in good working order to provide Energy in an amount at its temperature-adjusted DMNC within fifteen (15) minutes of remote start-up.

15.6.1.4 A Transmission Owner receiving the information specified in Section 15.6.1.2 of this Rate Schedule shall confirm to the ISO and the Supplier whether the Transmission Owner has the ability to remotely start up a block of generator units that the Supplier has offered for Quick Start Reserves. This confirmation informs the Supplier that the Transmission Owner or the ISO may elect to purchase Quick Start Reserves from each block of generator units that the Supplier has offered for Quick Start Reserves.

15.6.2 Purchase and Selection of Quick Start Reserves and Associated Duties

15.6.2.1 When a Transmission Owner has issued confirmation pursuant to Section 15.6.1.4 of this Rate Schedule and requires Quick Start Reserves, the Transmission Owner may purchase Quick Start Reserves from the Supplier by telephonic request; provided, however, that the Transmission Owner shall not purchase Quick Start Reserves unless the Transmission Owner has received the ISO's concurrence with the proposed purchase of Quick Start Reserves. The telephonic request shall specify the starting time and either the number of MWs of Quick Start Reserves required or the block of generator units from which the

Supplier is to sell Quick Start Reserves. In addition, the telephonic request shall, if available and for information purposes only, specify the estimated number of hours for which the Transmission Owner intends to purchase Quick Start Reserves. The Transmission Owner shall give written notice by electronic mail (or fax if electronic mail is not available) to each of the Supplier and the ISO of the telephonic request within ten (10) minutes of making the telephonic request, and the written notice by electronic mail or fax shall provide the same information specified in the Transmission Owner's telephonic request and shall also provide the time of the telephonic request. If the Supplier has not received such written notice or disagrees with its contents, the Supplier shall give notice by electronic mail (or fax if electronic mail is not available) to each of the ISO and the Transmission Owner confirming the telephonic request, and the notice by electronic mail or fax shall provide the same information specified in the Transmission Owner's telephonic request and shall also provide the time of the telephonic request.

15.6.2.2 A Transmission Owner shall stop purchasing some or all the Quick Start Reserves from a Supplier upon giving telephonic notice to the Supplier that the Transmission Owner no longer requires some or all the Quick Start Reserves; provided, however, that the Transmission Owner shall not stop the purchase of Quick Start Reserves without the ISO's concurrence. The Transmission Owner shall give written notice by electronic mail (or fax if electronic mail is not available) to each of the Supplier and the ISO of the telephonic notice within ten (10) minutes of providing the telephonic notice, and the written notice by

electronic mail or fax shall provide the time of the telephonic notice. If the Supplier has not received such written notice or disagrees with its contents, the Supplier shall give notice by electronic mail (or fax if electronic mail is not available) to each of the ISO and the Transmission Owner of the telephonic notice, and the notice by electronic mail or fax shall provide the same information specified in the Transmission Owner's telephonic notice and shall also provide the time of the telephonic notice.

15.6.2.3 The ISO shall maintain complete and accurate records of all notices received by electronic mail or fax pursuant to Sections 15.6.2.1 and 15.6.2.2 of this Rate Schedule.

15.6.2.4 A Supplier offering Quick Start Reserves that receives a telephonic request to purchase or to select Quick Start Reserves shall set one or more blocks of generator units to Quick Start Mode as requested within ten (10) minutes of the telephonic request; provided, however, that the Supplier shall have no obligation to set a block of generator units to or to maintain a block of generator units in Quick Start Mode during (i) periods of forced outage, (ii) maintenance outages that are approved in advance pursuant to the ISO Services Tariff, or (iii) any period when the requested block of generator units is producing Energy.

15.6.2.5 During any period when the Transmission Owner has not purchased Quick Start Reserves from an offered block of generator units, the Supplier shall not be required to set the block of generator units to or to maintain the block of generator units in Quick Start Mode, subject to the requirement that the Supplier set the block of generator units to Quick Start Mode within ten (10) minutes of a request

pursuant to Section 15.6.2.1 of this Rate Schedule.

15.6.2.6 A Supplier offering Quick Start Reserves shall maintain Hour-Ahead Bids for Energy at all times for each of the Supplier's block of generator units comprising the offered, purchased, or selected Quick Start Reserves, and shall maintain these Bids in the Real-Time Market.

15.6.3 Duty to Produce Energy

15.6.3.1 A Transmission Owner may remotely start up any block of generator units that is providing Quick Start Reserves. Upon remote start-up, the Transmission Owner shall give notice to the ISO that the block of generator units have been started up out of merit for local reliability. A Transmission Owner may dispatch off a block of generator units started up out of merit when Energy from the block of generator units is no longer required for local reliability, subject to any minimum run time of the block of generator units; provided, however, that the Transmission Owner shall not dispatch off the block of generator units without the ISO's concurrence.

15.6.3.2 During each period when a Transmission Owner has purchased Quick Start Reserves, the Supplier shall respond to each remote start-up order from the Transmission Owner, and shall cause the Supplier's remotely started up block of generator units to be synchronized and at full output within fifteen (15) minutes.

15.6.4 Failure to Achieve Timely Synchronization

If a Supplier that has sold Quick Start Reserves fails to have the block of generator units synchronized in the amount of the Energy Bid pursuant to Section 15.6.2.6 of this Rate Schedule within fifteen (15) minutes of a remote start-up, the Supplier shall be subject to the provisions

applicable to Suppliers of 10-Minute Non-Synchronized Reserves and 30-Minute Reserves that fail to provide Energy within the time allotted; provided, however, that charges against Quick Start Reserves payments shall be based upon the blended rate of 85% of $P_{10MNSR,h}$ plus 15% of $P_{30MR,h}$, as applied in Section 15.6.5.1 of this Rate Schedule.

15.6.5 Payments to Suppliers; Payments by Load Serving Entities

15.6.5.1 A Supplier that provides Quick Start Reserves shall receive each Billing Period a payment for each block of generator units that provided Quick Start Reserves in any hour of the previous Billing Period, unless the block of generator units also produced Energy during the hour. The amount of this payment shall equal:

$$\sum_{h} (C_h * (0.85 * P_{10MNSR,h} + 0.15 * P_{30MR,h}) - Q_h * P_{30MR,h})$$

where:

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

C = Capacity in MWs of Hour-Ahead Bids for Energy for the block of generator units

P_{10MNSR} = Price of New York City 10-Minute Non-Synchronized Reserve in the Day-Ahead Market

P_{30MR} = Price of New York City 30-Minute Reserve in the Day-Ahead Market

Q = Quantity of MWs from the block of generator units selected to provide 30-Minute Reserve.

15.6.5.2 Any block of generator units requested for Quick Start Reserves for any portion of an hour shall be deemed to have provided Quick Start Reserves for the entire hour unless the block of generator units also produced Energy during the

hour.

15.6.5.3. In addition to payments due to a Supplier of Quick Start Reserves pursuant to Section 15.6.5.1 of this Rate Schedule, the Supplier shall be eligible to receive payments for Energy, Installed Capacity, Operating Reserves, and other Ancillary Services pursuant to the other provisions of this Services Tariff.

15.6.5.4 Amounts due to a Supplier pursuant to this Rate Schedule that are attributable to local reliability shall be recovered from LSEs in the Transmission District of the Supplier selling the Quick Start Reserves on the basis of each LSE's contribution to Load share in the Billing Period in which the payment obligation is incurred. Amounts attributable to local reliability are those amounts incurred pursuant to Sections 15.6.2.1 and 15.6.3.1 of this Rate Schedule.

15.6.6 Dispute Resolution

15.6.6.1 In the event of a dispute between a Transmission Owner and a Supplier of Quick Start Reserves regarding the hours or MWs of Quick Start Reserves purchased by a Transmission Owner or the Energy output achieved within fifteen (15) minutes of a remote start-up, the Transmission Owner and Supplier shall attempt to resolve the dispute promptly, and either party may request the ISO to refer to the ISO logs to help resolve the dispute. If a Transmission Owner and a Supplier selling Quick Start Reserves cannot resolve any dispute regarding the hours or MWs of Quick Start Reserves purchased by a Transmission Owner or the Energy output achieved within fifteen (15) minutes of a remote start-up within fifteen (15) days, then the Transmission Owner and Supplier may resolve the dispute through the ISO's Expedited Dispute Resolution Procedures.

15.6.6.2 Disputes other than those addressed pursuant to Section 15.6.6.1 of this Rate Schedule may be resolved through the ISO's Dispute Resolution Process.

15.7 Rate Schedule 7 - Charges for Intermittent Power Resource Forecasting Services

The ISO shall charge each Intermittent Power Resource, except for Intermittent Power Resources in a DER Aggregation, that depends on wind or solar energy as its fuel that is interconnected in the New York Control Area in order to provide Energy to the LBMP Market or bilaterally to a Load internal or external to the NYCA, pursuant to this ISO Services Tariff or the NYISO OATT, and that has entered commercial operation, for forecasting service pursuant to this Rate Schedule, provided however no charge shall be assessed against any Intermittent Power Resource in commercial operation as of January 1, 2002 with nameplate capacity of 12 MWs or fewer.

The ISO shall calculate and assess such charges each Billing Period.

15.7.1 Responsibilities

The ISO shall cal**c**ulate a forecasting service charge which shall include a fixed component and a component that varies by the nameplate capacity of the Intermittent Power Resource subject to this charge ("Forecasting Service Charge"). Such charge shall be based upon the costs the NYISO incurs in producing a forecast of the expected generation output of each Intermittent Power Resource subject to this charge.

15.7.2 Charges

Each Billing Period, the ISO shall assess to each Intermittent Power Resource subject to this charge the portion of the following monthly Forecasting Service Charge allocated to that Billing Period:

- $500.00 as a fixed fee; and
- $6.20 / MW of name plate capacity.

15.8 Rate Schedule 8 – Payments to RMR Generators

15.8.1 Payment to an RMR Generator Providing Service Pursuant to an RMR Agreement with an Availability and Performance Rate

The ISO shall make a payment each Billing Period to each RMR Generator providing service pursuant to an RMR Agreement with an Availability and Performance Rate that has been accepted for filing by the Commission, or the ISO may pay subject to refund pending Commission action. The payment shall equal:

$$\sum_{d \in P} \left(RMRAvoidCost_{g,d} + VarCost_{g,d} \right)$$

Where:

d = the relevant market day;

P = the relevant Billing Period;

g = the relevant RMR Generator that is providing service under an Availability and Performance Rate established pursuant to the ISO Tariffs and an RMR Agreement between the ISO and the RMR Generator;

$RMRAvoidCost_{g,d}$ = RMR Avoidable Cost amount for RMR Generator *g* for day *d* that has been accepted for filing by the Commission, or as calculated by the ISO in accordance with Sections 38.8 and 38.17 of the OATT pending Commission action, shaped on a Capability Period basis, and Additional Costs in accordance with Section 38.16 of the OATT;

$$VarCost_{g,d} = Energy_{g,d} + AncServices_{g,d} + VSS_{g,d} + RS_{g,d}$$

Where:

$Energy_{g,d}$ = the energy cost of RMR Generator *g* for day *d*. The cost of all energy MWhs that are scheduled and produced in real-time by RMR Generator *g* that do not exceed RMR Generator *g*'s Day-Ahead schedule shall be equal to the lesser of RMR Generator *g*'s Day-Ahead reference levels and RMR Generator *g*'s Day-Ahead Bids. The cost of all energy MWhs that are scheduled and produced in real-time (including Compensable Overgeneration, if any) that exceed RMR Generator g's Day-Ahead schedule (if any) shall be equal to the lesser of RMR Generator *g*'s real-time reference levels and RMR Generator *g*'s real-time Bids;

$AncServices_{g,d}$ = the cost of Operating Reserves and Regulation Service for RMR Generator *g* for day *d*. The cost of all MWhs of Operating Reserves that are scheduled and of Regulation Service that are scheduled and provided in real-time by RMR

Generator *g* that do not exceed RMR Generator *g*'s Day-Ahead schedule shall be equal to the lesser of RMR Generator *g*'s Day-Ahead reference levels and RMR Generator *g*'s Day-Ahead Bids. The cost of all MWhs of Operating Reserves and Regulation Service that are scheduled and provided in real-time by RMR Generator *g* that exceed RMR Generator *g*'s Day-Ahead schedule (if any) shall be equal to the lesser of RMR Generator *g*'s real-time reference levels and RMR Generator *g*'s real-time Bids;

$VSS_{g,d}$ = the Voltage Support Service payment for RMR Generator *g* for day *d* pursuant to Rate Schedule 2 of the ISO Services Tariff;

$RS_{g,d}$ = the Restoration Services payment for RMR Generator *g* for day *d* pursuant to Rate Schedule 5 of the ISO Services Tariff.

15.8.2 Performance Incentive Payment

The ISO will pay on a monthly basis an RMR Generator that is providing service pursuant to an RMR Agreement with an Availability and Performance Rate any Performance Incentive payment owed to that RMR Generator for its performance in that month in accordance with the following formulae.

PI_m = the amount of the Performance Incentive payment, calculated for each month *m*, and is a dollar value calculated as:

$$PI_m = \frac{1}{12} PI_{max} * \begin{cases} 50\%, & \text{for } LB_{PI} \leq PF_m < UB_{PI} \\ 80\%, & \text{for } UB_{PI} \leq PF_m < TL_{PI} \\ 100\%, & \text{for } TL_{PI} \leq PF_m \end{cases}$$

Where:

PI_{max} = the maximum annual Performance Incentive payment, calculated as 5% of the RMR Generator's *Non-CapEx Avoidable Costs;*

$Non\text{-}CapEx\ Avoidable\ Costs$ = the RMR Avoidable Costs the RMR Generator is authorized to recover annually, pursuant to an Availability and Performance Rate that has been accepted for filing by the Commission, or that the RMR Generator is recovering subject to refund pending Commission action, less the Capital Expenditures included in such RMR Avoidable Costs;

LB_{PI} = the Bandwidth Lower Bound, a percentage defined as:

$$LB_{PI} = \begin{cases} 0.9 * BL_{PI}, & if\ BL_{PI} < 50\% \\ BL_{PI} - 5\%, & if\ BL_{PI} \geq 50\% \end{cases}$$

UB_{PI} = the Bandwidth Upper Bound, a percentage defined as:

$$UB_{PI} = BL_{PI} + min\left\{\frac{1}{3}(100\% - BL_{PI}),\ \max\left\{5\%, \frac{1}{10}(100\% - BL_{PI})\right\}\right\}$$

TL_{PI} = the Target Limit, a percentage defined as:

$$TL_{PI} = BL_{PI} + min\left\{\frac{2}{3}(100\% - BL_{PI}), max\left\{10\%, \frac{1}{5}(100\% - BL_{PI})\right\}\right\}$$

Where:

BL_{PI} = the Baseline percentage determined for the RMR Generator's performance, as set forth in the RMR Generator's RMR Agreement.

PF_m = the RMR Performance Factor for month m, a percentage defined as:

$$PF_m = \quad 100\% - \frac{\sum_{t=t_0}^{T} (max\{PLU_t - Pr_t, 0\})}{\sum_{t=t_0}^{T} PLU_t}$$

Where:

t_0 = the first RTD interval of month *m*;

T = the last RTD interval of month *m*;

Pr_t = the Real-Time output of the RMR Generator over RTD interval *t*, in MW; and

PLU_t = the Penalty Limit for Under-Generation of the RMR Generator over RTD interval *t*, expressed in MW, calculated in accordance with the ISO's Billing and Accounting Manual.

15.8.3 Availability Incentive Payment

The ISO will pay on a Capability Period basis an RMR Generator that is providing service pursuant to an RMR Agreement with an Availability and Performance Rate for any Availability Incentive payment owed to that RMR Generator. The ISO will make the Availability Incentive payment in the Billing Period following the first month of the Capability Period for a payment

earned for the previous Capability Period in accordance with the following formulae.

AI_{cp} = the amount of the Availability Incentive, calculated for each Capability Period *cp*, and is a dollar value calculated as:

$$AI_{cp} = \frac{1}{2} AI_{max} * \begin{cases} 50\%, & \text{for } LB_{AI,cp} \leq EAF_{cp} < UB_{AI,cp} \\ 80\%, & \text{for } UB_{AI,cp} \leq EAF_{cp} < TL_{AI,cp} \\ 100\%, & \text{for } TL_{AI,cp} \leq EAF_{cp} \end{cases}$$

Where:

AI_{max} = the maximum Availability Incentive payment, calculated as 20% of the RMR Generators *Non-CapEx Avoidable Costs;*

$Non\text{-}CapEx\ Avoidable\ Costs$ = the RMR Avoidable Costs the RMR Generator is authorized to recover annually, pursuant to an Availability and Performance Rate that has been accepted for filing by the Commission, or that the RMR Generator is recovering subject to refund pending Commission action, less the Capital Expenditures included in such RMR Avoidable Costs;

$LB_{AI,cp}$ = the Bandwidth Lower Bound, a percentage defined as:

$$LB_{AI,cp} = \begin{cases} 0.9 * BL_{AI,cp}, & if\ BL_{AI,cp} < 50\% \\ BL_{AI,cp} - 5\%, & if\ BL_{AI,cp} \geq 50\% \end{cases}$$

$UB_{AI,cp}$ = the Bandwidth Upper Bound, a percentage defined as:

$$UB_{AI,cp} = BL_{AI,cp} + min\left\{\frac{1}{3}\left(100\% - BL_{AI,cp}\right),\ \max\left\{5\%, \frac{1}{10}\left(100\% - BL_{AI,cp}\right)\right\}\right\}$$

$TL_{AI,cp}$ = the Target Limit, a percentage defined as:

$$TL_{AI,cp} = BL_{AI,cp} + min\left\{\frac{2}{3}\left(100\% - BL_{AI,cp}\right), max\left\{10\%, \frac{1}{5}\left(100\% - BL_{AI,cp}\right)\right\}\right\}$$

Where:

$BL_{AI,cp}$ = the Baseline percentage for Capability Period *cp* determined for the RMR Generator's availability, as set forth in the RMR Generator's RMR Agreement;

EAF_{cp} = the RMR Generator's equivalent availability factor for Capability Period *cp*, a percentage defined as:

$$EAF_{cp} = 100\% * \left(\frac{(AH - (DH_{EU} + DH_{EP} + DH_{ESE}))}{PH}\right)$$

Where:

AH = the RMR generator's available hours, calculated for Capability Period *cp* in accordance with ISO procedures;

PH = the RMR Generator's period hours, calculated for Capability Period *cp* in accordance with ISO procedures, as the number of hours that the RMR Generator was in an active state;

DH_{EU} = the RMR Generator's unplanned derated hours, calculated for Capability Period *cp* in accordance with ISO procedures, as the product of unplanned derated hours and size of reduction, divided by net maximum capacity;

DH_{EP} = the RMR Generator's planned derated hours, calculated for Capability Period *cp* in accordance with ISO procedures, as the product of planned derated hours and size of reduction, divided by net maximum capacity; and

DH_{ESE} = the RMR Generator's net maximum capacity, determined in accordance with ISO procedures, less net dependable capacity, determined in accordance with ISO procedures, multiplied by available hours in accordance with ISO procedures, and divided by net maximum capacity.

GADS Data used to calculate Availability Incentive payments, as it may be modified by the ISO, shall be subject to review, challenge, and correction in accordance with Section 7.4 of the ISO Services Tariff.

15.8.4 Limitation on Total Penalties, Sanctions and Deficiency Charges Assessed to RMR Generators Providing Service Pursuant to an RMR Agreement with an Availability and Performance Rate

An RMR Generator that is providing service pursuant to an RMR Agreement with an Availability and Performance Rate is subject to all of the penalties, sanctions, deficiency charges and any similar charges, except for under-generation penalties (collectively, for purposes of this paragraph, "penalties"), that may apply to Generators under the ISO Tariffs. *Provided, however*, that the total amount of penalties that can be assessed to an RMR Generator that is providing service pursuant to an RMR Agreement with an Availability and Performance Rate shall be

capped at the total, cumulative amount of Performance Incentive payments and Availability Incentive payments computed by the ISO to be due to that RMR Generator through the end of the month in which the penalty or penalties are charged. The ISO shall charge any penalties to the RMR Generator and remit the revenues from each penalty, or any reduced amount, in accordance with the applicable provisions of the ISO Services Tariff.

15.8.5 Payment to an RMR Generator Providing Service Pursuant to an RMR Agreement with a Rate Other Than an Availability and Performance Rate

The ISO shall make a payment each Billing Period to each RMR Generator providing service pursuant to an RMR Agreement with a rate other than an Availability and Performance Rate that has been accepted for filing by the Commission, or the ISO may pay subject to refund pending Commission action. The payment shall equal:

$$\sum_{d \in P} \left(RMRCost_{g,d} + VarCost_{g,d} \right)$$

Where:

g = the relevant RMR Generator that is providing service under a rate other than an Availability and Performance Rate;

$RMRCost_{g,d}$ = the costs RMR Generator g is authorized to recover for day d pursuant to a rate for RMR Generator g that has been accepted for filing by the Commission, or that RMR Generator g is recovering subject to refund pending Commission action, shaped on a Capability Period basis, and Additional Costs in accordance with Section 38.16 of the OATT.

The definitions of the remaining variables in this equation are identical to the definitions for such variables set forth in Section 15.8.1 above.

15.8.6 Payment to an Interim Service Provider

Generator retained as Interim Service Provider—consistent with the rules set forth in Section 38.13 of the OATT and Sections 23.6 and 5.14.1.1 of the Services Tariff, commencing

on the latest of (a) the 181st day after the ISO posts its determination that a Generator Deactivation Notice is complete, or (b) ten days after the ISO posts a STAR that assessed the Generator's deactivation, or (c) the Generator's requested deactivation date, the ISO shall make a payment each Billing Period to each Generator that remains in service as an Interim Service Provider. Generators that are in an ICAP Ineligible Forced Outage shall not be compensated as Interim Service Providers.

Only system protection facilities retained as Interim Service Provider—consistent with the rules set forth in Section 38.13 of the OATT, for a Generator that submitted a Generator Deactivation Notice to be Retired, commencing on the latest of (a) the 181st day after the ISO posts its determination that the Generator Deactivation Notice is complete, or (b) ten days after the ISO posts a STAR that assessed the Generator's deactivation, or (c) the Generator's requested deactivation date, or (d) the day after the generating unit(s) are deactivated, the ISO shall make a payment each Billing Period to each Generator as an Interim Service Provider that maintains in-service the step-up transformer(s) and/or other system protection facilities that the ISO designates. Generators that are in a Mothball Outage or an ICAP Ineligible Forced Outage shall not be compensated as Interim Service Providers for maintaining in-service their step-up transformer(s) or other system protection facilities.

The payment to an Interim Service Provider shall equal:

$$\sum_{d \in P} \left(RMRAvoidCost_{g,d} + VarCost_{g,d} \right)$$

Where:

d = the relevant market day;

P = the relevant Billing Period;

g = the relevant Generator that satisfies the conditions set forth in Section 38.13 of the OATT, and Sections 23.6, 5.14.1.1 and 15.8.6 of the Services Tariff;

$RMRAvoidCost_{g,d}$ = the Avoidable Cost amount for Generator *g* for day *d* calculated by the ISO in accordance with Sections 38.8, 38.16 and 38.17 of the OATT, shaped on a Capability Period basis. The NYISO will incorporate Preexisting Capacity Bilaterals into its calculation of $RMRAvoidCost_{g,d}$ for Interim Service Providers consistent with the rules set forth below;

$$VarCost_{g,d} = Energy_{g,d} + AncServices_{g,d} + VSS_{g,d} + RS_{g,d}$$

Where:

$Energy_{g,d}$ = the energy cost of Generator *g* for day *d*. The cost of all energy MWhs that are scheduled and produced in real-time by Generator *g* that do not exceed Generator *g*'s Day-Ahead schedule shall be equal to the lesser of Generator *g*'s Day-Ahead reference levels and Generator *g*'s Day-Ahead Bids. The cost of all energy MWhs that are scheduled and produced in real-time (including Compensable Overgeneration, if any) that exceed Generator g's Day-Ahead schedule (if any) shall be equal to the lesser of Generator *g*'s real-time reference levels and Generator *g*'s real-time Bids;

$AncServices_{g,d}$ = the cost of Operating Reserves and Regulation Service for Generator *g* for day *d*. The cost of all MWhs of Operating Reserves that are scheduled and of Regulation Service that are scheduled and provided in real-time by Generator *g* that do not exceed Generator *g*'s Day-Ahead schedule shall be equal to the lesser of Generator *g*'s Day-Ahead reference levels and Generator *g*'s Day-Ahead Bids. The cost of all MWhs of Operating Reserves and Regulation Service that are scheduled and provided in real-time by Generator *g* that exceed Generator *g*'s Day-Ahead schedule (if any) shall be equal to the lesser of Generator *g*'s real-time reference levels and Generator *g*'s real-time Bids;

$VSS_{g,d}$ = the Voltage Support Service payment for Generator *g* for day *d* pursuant to Rate Schedule 2 of the ISO Services Tariff;

$RS_{g,d}$ = the Restoration Services payment for Generator *g* for day *d* pursuant to Rate Schedule 5 of the ISO Services Tariff.

If an Interim Service Provider has a Preexisting Capacity Bilateral, as such term is defined in Section 5.14.1.1 of the Services Tariff, then the ISO will reduce the *RMRAvoidCost* it calculates for the Interim Service Provider to reflect up to the revenues the ISO determines the Interim Service Provider is expected to receive under the Preexisting Capacity Bilateral.

If the Interim Service Provider's Preexisting Capacity Bilateral is with an Affiliate, or was entered into less than one year before the ISO received the Interim Service Providers Generator Deactivation Notice, then the *RMRAvoidCost* the ISO calculates for the Interim

Service Provider shall be reduced by up to the revenues that the ISO determines the Interim Service Provider would reasonably be expected to receive if offered its Unforced Capacity at $0.00/kW-month into the ICAP Spot Market Auction conducted for the relevant Obligation Procurement Period based on the ISO's forecast of the Market-Clearing Price for the applicable ICAP Spot Market Auction.

Payments pursuant to this Section 15.8.6 shall cease 365 days after the Short-Term Assessment of Reliability Start Date defined in Section 38.1 of the OATT.

15.8.7 Recovery of Capital Expenditures or Above Market Rates from Former RMR Generators, Former Interim Service Providers and Generators Returning from ICAP Ineligible Forced Outages

If, pursuant to the terms of an RMR Agreement, the ISO reimbursed all or a portion of the cost of a Capital Expenditure that was necessary to permit a Generator to provide service during the term of an RMR Agreement; or if the ISO reimbursed all or a portion of the cost of a Capital Expenditure that was necessary to permit a Generator to provide service as an Interim Service Provider; or if the NYISO compensated an RMR Generator pursuant to this Rate Schedule 8 amounts that exceeded the Generator's going-forward costs whilst providing RMR service; or if the ISO reimbursed all or a portion of the cost of a Generator in an ICAP Ineligible Forced Outage incurred to repair or replace its step-up transformer(s) and/or other system protection facilities; then in order for such a former RMR Generator or former Interim Service Provider or Generator that was in an ICAP Ineligible Forced Outage to be permitted to return to participating in the ISO Administered Markets while it is eligible to receive market-based rates, the Generator will be required to repay to the ISO the higher of the repayment obligation determined in accordance with Section 15.8.7.1 below, or the repayment obligation determined in accordance with Section 15.8.7.2 below. The higher of the two repayment obligations,

divided by the applicable number of repayment periods, is the "Monthly Repayment Obligation."

A Generator is "participating in the ISO Administered Markets while it is eligible to receive market-based rates" if the Generator (a) is not in a Mothball Outage or an ICAP Ineligible Forced Outage, and is not Retired, and (b) is not an RMR Generator or an Interim Service Provider.

The ISO shall apply the Monthly Repayment Obligation to the physical Generator that is a former RMR Generator or a former Interim Service Provider or that returns from an ICAP Ineligible Forced Outage, without regard to any changes in ownership or control of that Generator. The Monthly Repayment Obligation shall be applied whenever the former RMR Generator or former Interim Service Provider or Generator that returns from an ICAP Ineligible Forced Outage is participating in the ISO Administered Markets while it is eligible to receive market-based rates, until the applicable repayment obligation has been fully repaid. The Monthly Repayment Obligation shall not be imposed while a former RMR Generator or former Interim Service Provider or Generator that returns from an ICAP Ineligible Forced Outage is in a Mothball Outage or an ICAP Ineligible Forced Outage, or is Retired. If a Generator that is subject to a Monthly Repayment Obligation returns from being Retired, or from being in a Mothball Outage, or from an ICAP Ineligible Forced Outage, to participate in the ISO Administered Markets while it is eligible to receive market-based rates, then the ISO shall recalculate and reinstate an updated Monthly Repayment Obligation.

15.8.7.1 Recovery of Capital Expenditures from Former RMR Generators, Former Interim Service Providers and Generators Returning from ICAP Ineligible Forced Outages

If, pursuant to the terms of an RMR Agreement, the ISO reimbursed all or a portion of the cost of a Capital Expenditure that was incurred to permit an RMR Generator to provide

service during the term of the RMR Agreement, or if the ISO reimbursed all or a portion of the cost of a Capital Expenditure that was incurred to permit a Generator to provide service as an Interim Service Provider, and the Generator is no longer an Interim Service Provider or the subject of any RMR Agreement, or if the ISO reimbursed all or a portion of the cost of a Generator in an ICAP Ineligible Forced Outage incurred to repair or replace its step-up transformer(s) and/or other system protection facilities, then in order for the ISO to permit the Generator to be offered into or be scheduled in any ISO Administered Markets while it is eligible to receive market-based rates, the cost of Capital Expenditures (if any) that the ISO paid to enable the former RMR Generator to provide service under an RMR Agreement or to enable a former Interim Service Provider to provide service, or for a Generator in an ICAP Ineligible Forced Outage to repair or replace its step-up transformer(s) and/or other system protection facilities, less depreciation, plus interest, must be repaid to the ISO on a monthly basis over the period specified in the definition of "*mCapEx*" below. Depreciation will be calculated for each Capital Expenditure at the time the former RMR Generator or former Interim Service Provider or Generator returning from an ICAP Ineligible Forced Outage proposes to re-enter the ISO Administered Markets.

A Generator that was an RMR Generator or an Interim Service Provider that deactivated or a Generator in an ICAP Ineligible Forced Outage that the ISO reimbursed for repairing or replace its step-up transformer(s) and/or other system protection facilities, and that wants to return to participating in any of the ISO Administered Markets while it is eligible to receive market-based rates must give the ISO at least 60 days advance notice of its desire to return to the ISO Administered Markets in order to permit the ISO to determine its Monthly Repayment Obligation (if any) and any associated credit requirement.

The following formula shall be used to determine the repayment obligation:

$$RMRCapExRecovery\ repayment\ obligation = \sum_{i \in I} \left(\sum_{j \epsilon M} A_{ij} - \sum_{k \in Y} P_{ik} \right)$$

Where:

i = a Capital Expenditure in *I*, the set of all Capital Expenditures for the former RMR Generator or former Interim Service Provider or Generator returning from an ICAP Ineligible Forced Outage;

j = a month in *M*, the set of all months that the former RMR Generator or former Interim Service Provider or Generator returning from an ICAP Ineligible Forced Outage received payment for Capital Expenditure *i*;

k = a year in *Y*, the set of all years beginning with the year Capital Expenditure *i* entered service or was otherwise integrated into the RMR Generator or Interim Service Provider or Generator returning from an ICAP Ineligible Forced Outage, or the year the NYISO terminated the RMR Agreement if Capital Expenditure *i* was not completed or did not enter service while the Generator was operating under an RMR Agreement, and continuing to the present year;

A_{ij} = the payment made to the former RMR Generator or former Interim Service Provider or Generator returning from an ICAP Ineligible Forced Outage in month *j*, for Capital Expenditure *i*;

P_{ik} = the annual depreciation expense, determined by the ISO, for Capital Expenditure *i* in year *k*; and

For the component of a former RMR Generator's or former Interim Service Provider's or Generator returning from an ICAP Ineligible Forced Outage's Above Market Revenues that is Capital Expenditures, the value derived in the calculation above shall be divided by "*mCapEx*" months;

mCapEx = For a former RMR Generator, the shorter of 36 months or twice the duration of the applicable RMR Agreement in months. For a former Interim Service Provider or for a Generator returning from an ICAP Ineligible Forced Outage, twelve months. Alternatively, if the former RMR Generator or former Interim Service Provider or Generator returning from an ICAP Ineligible Forced Outage elects to repay its entire obligation before it begins participating in the ISO Administered Markets at market-based rates, then *mCapEx* shall be one month.

Accumulated interest will be computed on a quarterly basis and assessed based on the dates the ISO paid the former RMR Generator or former Interim Service Provider or Generator

returning from an ICAP Ineligible Forced Outage for each Capital Expenditure. Following the date a former RMR Generator or former Interim Service Provider or Generator returning from an ICAP Ineligible Forced Outage returns to participating in the ISO Administered Markets while it is eligible to receive market-based rates, a fixed interest rate will be used to determine the Monthly Repayment Obligation.

The repayment obligation specified in this Section 15.8.7.1 shall remain in effect until all Capital Expenditures that are due (as determined in accordance with the formula set forth above) have been repaid. As explained in Section 15.8.7 of this Rate Schedule 8, the repayment obligation shall take effect, be reinstated, or remain in effect (as appropriate) (i) if a former RMR Generator does not deactivate at the conclusion of its RMR Agreement, or (ii) if a former Interim Service Provider does not deactivate at the conclusion of the 365 Day Notice Period, or (iii) if a former RMR Generator that entered a Mothball Outage, an ICAP Ineligible Forced Outage or Inactive Reserves returns to service from such state, or (iv) if a former Interim Service Provider that entered a Mothball Outage or an ICAP Ineligible Forced Outage returns to service from such state, or (v) if a former RMR Generator or former Interim Service Provider becomes Retired and subsequently returns to service as a new Generator, and/or (vi) if a former RMR Generator or former Interim Service Provider is sold, leased or otherwise transferred to a new owner or owners and remains in service or returns to service. If the ISO reimbursed all or a portion of the cost of a Generator in an ICAP Ineligible Forced Outage incurred to repair or replace its step-up transformer(s) and/or other system protection facilities, the repayment obligation shall take effect, be reinstated, or remain in effect (as appropriate) (i) if the Generator returns to service from its ICAP Ineligible Forced Outage, or (ii) if the Generator entered a Mothball Outage, an ICAP Ineligible Forced Outage or Inactive Reserves and returns to service from such state, or

(iii) if the Generator becomes Retired and subsequently returns to service as a new Generator, and/or (iv) if the Generator is sold, leased or otherwise transferred to a new owner or owners and remains in service or returns to service.

15.8.7.2 Recovery of Above Market Revenues from Former RMR Generators

If the ISO made payments to a Generator under Section 15.8.5 of this Rate Schedule 8 to permit the Generator to provide service during the applicable term of an RMR Agreement, and the former RMR Generator is no longer the subject of any RMR Agreement, and the former RMR Generator continues participating in, or returns to, the ISO Administered Markets while it is eligible to receive market-based rates; then the cost of the Above Market Revenues (including but not limited to the ISO's reimbursement of the cost of Capital Expenditures), that the ISO paid to compensate the Generator for providing RMR service, less depreciation where applicable, plus interest, must be repaid to the ISO on a monthly basis. The period over which Above Market Revenues must be repaid is specified in the definition of "*mAMR*" below.

The following formula shall be used to determine the Above Market Revenue repayment obligation:

$$Above\ RMRAvoidCost\ Revenue_g = max\left\{0,\ \sum_{d \in ToS}\left(RMRCost_{g,d} - RMRAvoidCost_{g,d}\right)\right\}$$

Where:

Above RMRAvoidCost Revenue $_g$ = the difference between (x) the total revenues Generator g would have been eligible to receive in reimbursement of its RMR Avoidable Costs during the term of the RMR Agreement if it had been compensated at a rate developed in accordance with Section 15.8.1 of this Rate Schedule 8 (excluding any payments that Generator *g* would have been eligible to receive as Performance Incentives or Availability Incentives), and (y) the total revenues Generator g received in accordance with its accepted RMR Agreement to reimburse RMR Costs during the term of that RMR Agreement, paid in accordance with Section 15.8.5 of this Rate Schedule 8;

ToS = the duration of the applicable RMR Agreement;

$RMRAvoidCost_{g,d}$ = The revenue Generator *g* would have received for day *d* if it had been compensated for its RMR Avoidable Costs at a rate developed by the ISO in accordance with Section 15.8.1 of this Rate Schedule 8 (without Performance Incentives or Availability Incentives), using the market participation, commitment, scheduling and dispatch that occurred on day *d*; and

$RMRCost_{g,d}$ = the payment RMR Generator *g* received for day *d* in accordance with Section 15.8.5 of this Rate Schedule 8, excluding payment for Variable Costs.

The *Above RMRAvoidCost Revenue* shall be divided by "*mAMR*" to determine the Monthly Repayment Obligation.

mAMR = the shorter of 36 months or twice the duration of the applicable RMR Agreement in months. Alternatively, if the former RMR Generator elects to repay its entire obligation before it begins participating in the ISO Administered Markets at market-based rates, then *mAMR* shall be one month.

Accumulated interest will be computed and assessed quarterly, on a *pro rata* basis, based on the date of payment to the Generator for each relevant Billing Period *P* (as defined in Section 15.8.1 of this Rate Schedule 8). Following the date a former RMR Generator returns to participating in the ISO Administered Markets while it is eligible to receive market-based rates, a fixed interest rate will be used to determine the Monthly Repayment Obligation.

The definitions of the remaining variables in this equation are identical to the definitions for such variables set forth in Sections 15.8.1 and 15.8.7.1 above.

The reimbursement obligation specified in this Section 15.8.7.2 shall remain in effect until the entire amount, including interest has been reimbursed. As explained in Section 15.8.7 of this Rate Schedule 8, the reimbursement obligation shall take effect, be reinstated, or remain in effect (as appropriate) whenever a former RMR Generator continues participating in, or returns to, the ISO Administered Markets while it is eligible to receive market-based rates. The reimbursement obligation shall continue to apply or shall be reinstated, as appropriate, when (i) a former RMR Generator that entered a Mothball Outage, an ICAP Ineligible Forced Outage or Inactive Reserves returns to service from such state, or (ii) a former RMR Generator becomes

Retired and subsequently returns to service as a new Generator, and/or (iii) a former RMR Generator is sold, leased or otherwise transferred to a new owner or owners and remains in service or returns to service.

15.9 Rate Schedule 9 -- Implementing Federal Duties on Imports of Electrical Energy from Canada

The terms of Schedule 22 of the ISO OATT are hereby incorporated by reference into this Tariff. In applying the terms of Schedule 22 of the ISO OATT in connection with this Tariff, all terms in Schedule 1 of the ISO OATT that are applicable to "Transmission Customers" shall be similarly applicable to "Customers" under this Rate Schedule 9, and the ISO shall interpret all other defined terms and cross references in Schedule 22 that are specific to the ISO OATT consistent with the similar terms and provisions of this Tariff, unless otherwise specified.

15.10 Rate Schedule 10 - Charges for Market Participants utilizing a Meter Services Entity in the ISO Wholesale markets

The ISO shall charge, and each Market Participant that uses a Meter Services Entity shall pay, the costs incurred by the ISO to audit a Market Participant's utilization of a Meter Services Entity for participation in the ISO wholesale markets. Meter Services Entities must comply with, i) periodic audits in accordance with ISO procedures and the ISO requirements found in Section 13.3.2.3.1 and ii) audits in accordance with ISO procedures and the ISO requirements found in Section 13.3.2.3.1 when the Market Participant enrolls new resources or modifies the metering scheme of existing resources.

The ISO shall calculate the costs of any such audits, inspections and/or tests and assess such charges each Billing Period as described in this Rate Schedule. The functions that will be subject to cost recovery will include only those costs that are incurred as a result of ISO's audit, inspection and/or test of the services being provided by a Meter Services Entity to a Market Participant. In accordance with ISO Procedures the ISO audit of a Meter Services Entity's services may involve, but is not limited to, the ISO review, inspection, performance testing and review of corrective actions taken in the following categories:

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

(B) Site meter configurations

(C) Meter compliance with ISO rules and procedures

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

(E) Telemetry and communication data and records

ISO cost recovery for each audit will be the sum of the ISO's labor costs to complete each audit task conducted by the ISO based on an hourly rate and a prorated cost of overhead. In addition, if the ISO utilizes a third party vendor to complete audit tasks, the cost of that vendor will be billed to the Market Participant utilizing a MSE for their meter services.

15.10.1 Responsibilities

The ISO shall calculate a Meter Services Entity audit services charge which shall be equal to the costs the ISO incurs in performing audits of Meter Services Entities, as described above in Services Tariff Section 13.3.2 for that Billing Organization.

15.10.2 Charges

In each Billing Period, the ISO shall assess any applicable Metering Services Entity audit services charges for each Billing Organization. Upon request, the NYISO will provide to the billing organization a detailed listing of the costs incurred for the given Billing Period.

16 Attachment A - Form Of Service Agreement For New York ISO Market Administration and Control Area Services Tariff

1.0 This Service Agreement dated as of _____ is entered into by and between the New York Independent System Operator ("ISO") and _____ ("the Customer").

2.0 The Customer represents and warrants that it has met all applicable requirements set forth in the ISO Market Administration and Control Area Services Tariff (the "ISO Services Tariff") and has complied with all applicable ISO Procedures. The Customer has submitted a Completed Application pursuant to Article 9 of the ISO Services Tariff.

The ISO agrees to provide and the Customer agrees to pay for Market Services and Control Area Services in accordance with the provisions of the Tariff and to satisfy all obligations under the terms and conditions of the ISO Services Tariff, as may be amended from time-to-time, filed with the Federal Energy Regulatory Commission (the "Commission"). The ISO and the Customer also agree that this Service Agreement shall be subject to, and shall incorporate by reference, all of the terms and conditions of the ISO Services Tariff and ISO Procedures.

It is understood that, in accordance with the ISO Services Tariff, the ISO may amend the terms and conditions of this Service Agreement by notifying the Customer in writing and making the appropriate filing with the Commission.

3.0 The Customer represents and warrants that:

(a) The Customer is an entity duly organized, validly existing and/or otherwise qualified to do business under the laws of the State of New York, and is in good standing under its [insert organizational document] and the laws of the State of [insert state of organization];

(b) This Service Agreement, or any Transaction entered into pursuant to the Service Agreement, as applicable, has been duly authorized;

(c) The execution, delivery and performance of this Service Agreement will not materially conflict with, constitute a material breach of, or a material default under, any of the terms, conditions, or provisions of any law or order of any agency of government, the [insert organizational document] of the Customer, any contractual limitation, organizational limitation or outstanding trust indenture, deed of trust, mortgage, loan agreement, other evidence of indebtedness, or any other agreement or instrument to which the Customer is a party or by which it or any of its property is bound, or result in a material breach of, or a material default under, any of the foregoing; and

(d) This Service Agreement is the legal, valid, and binding obligation of the Customer enforceable in accordance with its terms, except as it may be rendered unenforceable by reason of bankruptcy or other similar laws affecting creditors' rights, or general principles of equity.

The Customer warrants and covenants that, during the term of the Service Agreement the Customer shall be in compliance with all federal, state and local laws, rules and regulations related to the Customer's performance under the agreement.

4.0 Service under this Service Agreement shall commence on the later of: _____, or such other date as it is permitted to become effective by the Commission. Service under this Service Agreement shall terminate on _____.

5.0 The ISO agrees to provide and the Customer agrees to take and pay for, or to supply to the ISO, Energy, Capacity and Ancillary Services in accordance with the provisions of the ISO

Services Tariff and this Service Agreement.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below:

ISO:

_____
_____
_____

Customer:

_____
_____
_____

7.0 Cancellation Rights:

If the Commission or any regulatory agency having authority over this Service Agreement determines that any part of this Service Agreement must be changed, the ISO shall offer to the Customer an amended Service Agreement reflecting such changes. In the event that the Customer does not execute such an amendment within thirty (30) days, or longer if the Parties mutually agree to an extension, after the Commission's action, this Service Agreement and the amended Service Agreement shall be void.

8.0 Early Termination by the Customer:

The Customer may terminate service under this Service Agreement no earlier than ninety (90) days after providing the ISO with written notice of the Customer's intention to terminate; except that a Load Serving Entity must continue to take service under this Tariff as long as it continues to serve Load within the NYCA. In the event that tax-exempt financing of a Customer is jeopardized by its participation under this Service Agreement, the Customer may terminate this Service Agreement upon thirty (30) days prior written notice to the ISO. The Customer's provision of notice to terminate service under this Service Agreement shall not relieve the Customer of its obligation to pay any rates, charges, or fees due under this Service Agreement,

and which are owed as of the date of termination.

9.0 The Customer hereby appoints the ISO as its agent for the limited purpose of effectively transacting on the Customer's behalf in accordance with the Customer's written instructions, listed herein and the terms of the ISO Services Tariff and ISO Procedures. The Customer agrees to pay all amounts due and chargeable to the Customer in accordance with the terms of the ISO Services Tariff and ISO Procedures.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

ISO:_____

By: _____

Dated:_____

Title: _____

Customer:_____

By:_____

Dated:_____

Title:_____

17 Attachment B

17.1 LBMP Calculation

The Locational Based Marginal Prices ("LBMPs" or "prices") for Suppliers and Loads in the Real-Time Market will be based on the system marginal costs produced by the Real-Time Dispatch ("RTD") program and during intervals when certain conditions exist at Proxy Generator Buses, the Real-Time Commitment ("RTC") program. LBMPs for Suppliers and Loads in the Day-Ahead Market will be based on the system marginal costs produced by the Security Constrained Unit Commitment ("SCUC"). LBMPs calculated by SCUC and RTD will incorporate the incremental dispatch costs of Dispatchable Resources that would be scheduled to meet an increment of Load. For pricing purposes, the incremental dispatch costs of Fast-Start Resources that Bid ISO-Committed Flexible shall be adjusted to include start-up costs and minimum generation costs based on the Start-Up Bids and Minimum Generation Bids or mitigated Start-Up Bids and Minimum Generation Bids of each such Resource, as described in Section 17.1.1.2 below.

To the extent that tradeoffs exist between scheduling providers to produce Energy or reduce demand, and scheduling them to provide Regulation Service or Operating Reserves, LBMPs shall reflect the effect of meeting an increment of Load, given those tradeoffs, at each location on the Bid Production Cost associated with those services. As such, those LBMPs may incorporate: (i) Bids for Regulation Service or Operating Reserves; or (ii) shortage costs associated with the inability to meet a Regulation Service or Operating Reserves requirement under the Regulation Service Demand Curve set forth in Rate Schedule 3 of this ISO Services Tariff and Operating Reserve Demand Curves and Scarcity Reserve Demand Curve set forth in Rate Schedule 4 of this ISO Services Tariff. For the purposes of calculating LBMPs under this

Services Tariff Section 17, Energy withdrawals by Withdrawal-Eligible Generators are treated as negative generation, and can set price.

Additionally, for the purpose of calculating Real-Time LBMPs when RTD is committing and dispatching Resources meeting Minimum Generation Levels and capable of starting in ten minutes pursuant to Section 4.4.2.4 of this ISO Services Tariff, RTD shall include in the incremental dispatch cost of each such Resource a start-up cost based on the Start-Up Bid of each such Resource and shall assume for each such Resource a zero downward response rate.

17.1.1 LBMP Bus Calculation Method

System marginal costs will be utilized in an *ex ante* computation to produce Day-Ahead and Real-Time LBMP bus prices using the following equations.

The LBMP at bus i can be written as:

$$\gamma_i = \lambda^R + \gamma_i^L + \gamma_i^C$$

Where:

γ_i	=	LBMP at bus *i* in $/MWh
λ^R	=	the system marginal price at the Reference Bus
γ_i^L	=	Marginal Losses Component of the LBMP at bus *i* which is the marginal cost of losses at bus *i* relative to the Reference Bus
γ_i^C	=	Congestion Component of the LBMP at bus *i* which is the marginal cost of Congestion at bus *i* relative to the Reference Bus

The Marginal Losses Component of the LBMP at any bus i is calculated using

the equation:

$$\gamma_i^L = (DF_i - 1)\lambda^R$$

Where:

DF_i	=	delivery factor for bus *i* to the system Reference Bus and:

$$DF_i = \left(1 - \frac{\partial L}{\partial P_i}\right)$$

Where:

L = NYCA losses; and

P_i = injection at bus *i*

The Congestion Component of the LBMP at bus i is calculated using the equation:

$$\gamma_i^C = -\left(\sum_{k \in K}^{n} GF_{ik}\mu_k\right)$$

Where:

K = the set of Constraints;

GF_{ik} = Shift Factor for bus *i* on Constraint *k* in the pre- or post-Contingency case which limits flows across that Constraint (the Shift Factor measures the incremental change in flow on Constraint *k*, expressed in per unit, for an increment of injection at bus *i* and a corresponding withdrawal at the Reference Bus); and

μ_k = the Shadow Price of Constraint *k* expressed in $/MWh, provided however, this Shadow Price shall not exceed the Transmission Shortage Cost.

Substituting the equations for γ_i^L and γ_i^C into the first equation yields:

$$\gamma_i = \lambda^R + (DF_i - 1)\lambda^R - \sum_{k \epsilon K} GF_{ik}\mu_k$$

LBMPs will be calculated for the Day-Ahead and the Real-Time Markets. In the Day-Ahead Market, the three components of the LBMP at each location will be calculated from the SCUC results and posted for each of the twenty four (24) hours of the next day. The Real-Time LBMPs will be calculated and posted for each execution of RTD.

17.1.1.1 Determining Shift Factors and Incremental System Losses

For the purposes of pricing and scheduling, Shift Factors, GF_{ik}, and loss delivery factors, DF_i, will reflect expected power flows, including expected unscheduled power flows. When determining prices and schedules, SCUC, RTC and RTD shall include both the expected power flows resulting from NYISO interchange schedules (*see* Section 17.1.1.1.2), and expected unscheduled power flows (*see* Section 17.1.1.1.1). All NYCA Resource, NYCA Load and Proxy Generator Bus Shift Factors and loss delivery factors will incorporate internal and coordinated external transmission facility outages, power flows due to schedules, and expected unscheduled power flows.

17.1.1.1.1 Determining Expected Unscheduled Power Flows

In the Day-Ahead Market, expected unscheduled power flows will ordinarily be determined based on historical, rolling 30-day on-peak and off-peak averages. To ensure expected unscheduled power flows accurately reflect anticipated conditions, the frequency and/or period used to determine the historical average may be modified by the NYISO to address market rule, system topology, operational, or other changes that would be expected to significantly impact unscheduled power flows. The NYISO will publicly post the Day-Ahead on-peak and off-peak unscheduled power flows on its web site.

In the Real-Time Market, expected unscheduled power flows will ordinarily be determined based on current power flows, modified to reflect expected changes over the real-time scheduling horizon.

17.1.1.1.2 Determining Expected Power Flows Resulting from NYISO Interchange Schedules

In the Day-Ahead Market, for purposes of scheduling and pricing, SCUC will establish expected power flows for the ABC interface, JK interface and Hopatcong-Ramapo interconnection based on the following:

a. The percentage of PJM-NYISO scheduled interchange that is expected to flow over the Hopatcong-Ramapo interconnection;

    1) The expected flow over the Hopatcong-Ramapo interconnection may also be adjusted by a MW offset to reflect expected operational conditions;

b. The percentage of PJM-NYISO scheduled interchange that is expected to flow over the ABC interface;

    1) The expected flow over the ABC interface will include an additional Operational Base Flow as described in Attachment CC to the OATT;

c. The percentage of PJM-NYISO scheduled interchange (if any) that is expected to flow over the JK interface;

    1) The expected flow over the JK interface will include an additional Operational Base Flow as described in Attachment CC to the OATT.

The terms “ABC interface” and “JK interface” have the meaning ascribed to them in Attachment CC to the OATT.

The NYISO shall post the interchange percentage and Operational Base Flow values it is currently using to establish Day-Ahead and real-time expected Hopatcong-Ramapo interconnection, ABC interface and JK interface flows for purposes of scheduling and pricing on its web site. If the NYISO determines it is necessary to change the posted Hopatcong-Ramapo,

ABC or JK interchange percentage or Operational Base Flow values, it will provide notice to its Market Participants as far in advance of the change as is practicable under the circumstances.

In the Day-Ahead Market, scheduled interchange that is not expected to flow over the ABC interface, JK interface or Hopatcong-Ramapo interconnection (or on Scheduled Lines) will be expected to flow over the NYISO's other interconnections. Expected flows over the NYISO's other interconnections will be determined consistent with the expected impacts of scheduled interchange and consistent with shift factors and delivery factors calculated in accordance with Section 17.1.1.1, above.

For pricing purposes, flows in the Real-Time Market will be established for the ABC interface, JK interface, and Hopatcong-Ramapo interconnection based on the current flow, modified to reflect the expected incremental impacts of changes to interchange schedules over the forward scheduling horizon in a manner that is consistent with the method used to establish Day-Ahead power flows over these facilities. Expected flows over the NYISO's other interconnections will be determined based on the current flow, modified to reflect the expected incremental impacts of changes to interchange schedules over the forward scheduling horizon, and shall be consistent with shift factors and delivery factors calculated in accordance with Section 17.1.1.1, above.

17.1.1.1.3 Scheduled Lines and Chateauguay Interconnection with Hydro Quebec

For purposes of scheduling and pricing, the NYISO expects that power flows will ordinarily match the interchange schedule at Scheduled Lines, and at the NYCA's Chateauguay interconnection with Hydro Quebec, in both the Day-Ahead and Real-Time Markets.

17.1.1.2 Incremental Dispatch Costs for Pricing Fast-Start Resources

For the purpose of calculating LBMPs for the Day-Ahead and Real-Time Markets, the incremental dispatch costs of Fast-Start Resources that Bid ISO-Committed Flexible shall be adjusted to include start-up costs and minimum generation costs based on the Start-Up Bids and Minimum Generation Bids or mitigated Start-Up Bids and Minimum Generation Bids of each such Resource ("Adjusted Dispatch Costs"). For start-up costs, the ISO will use a Fast-Start Resource's single point Start-Up Bid if one is submitted (or the mitigated Bid, where appropriate). If a Fast-Start Resource does not submit a single point Start-Up Bid in the Real-Time Market, the ISO will use the point on the Fast-Start Resource's multi-point Start-Up Bid curve (or its mitigated multi-point Start-Up Bid curve, where appropriate) that corresponds to the shortest specified down time.

The ISO will use the following procedure to determine a Fast-Start Resource's Adjusted Dispatch Costs for each pricing interval in the Day-Ahead and Real-Time Markets. The ISO will determine the "cost-minimizing output level" that minimizes the average as-Bid operating cost ("minimum average cost") for that Fast-Start Resource in each hour of the Day-Ahead Market and in each RTD interval of the Real-Time Market. The average as-Bid operating cost for a Fast-Start Resource at a given operating level shall include the Fast-Start Resource's minimum generation costs and incremental energy costs to provide Energy at that operating level, based on the Resource's Bids, or mitigated Bids as appropriate. The average as-Bid operating cost may also include some or all of the Fast-Start Resource's start-up costs based on the Resource's Bids, or mitigated Bids as appropriate, in a given hour, to be determined as follows: (1) for the Day-Ahead Market, a Fast-Start Resource's average as-Bid operating cost to operate in a given hour will include start-up costs for the hour the Resource is scheduled to start; or (2) for the Real-

Time Market, a Fast-Start Resource's average as-Bid operating cost to operate in a given RTD interval will include the start-up costs for approximately the first fifteen minutes, among consecutive operating intervals, after the Resource is scheduled to start, *i.e.*, for each RTD interval that starts within the first fifteen minutes after the Resource is scheduled to start, the average as-Bid operating cost to operate in that interval will include start-up costs.

For all output levels less than or equal to the cost-minimizing output level, the ISO will set the Adjusted Dispatch Cost equal to the minimum average cost. For all output levels greater than the cost-minimizing output level, the ISO will set the Adjusted Dispatch Cost equal to the price on the Resource's Bid curve. The ISO will calculate Adjusted Dispatch Costs for each output level between the Fast-Start Resource's minimum operating level and its UOL_N or UOL_E (whichever is applicable).

For the purpose of calculating LBMPs for the Day-Ahead and Real-Time Markets, all Fast-Start Resources that Bid ISO-Committed Flexible are treated as flexible and able to be dispatched anywhere between zero (0) MW and their UOL_N or UOL_E (whichever is applicable). The dispatch for Fast-Start Resources, including Fixed Block Units, that participate as Co-located Storage Resources will consider CSR Scheduling Limits.

Additional rules for Fixed Block Units are set forth below in Section 17.1.2.1.2.

17.1.2 Real-Time LBMP Calculation Procedures

For each RTD interval, the ISO shall use the procedures described below in Sections 17.1.2.1-17.1.2.1.4 to calculate Real-Time LBMPs at each Load Zone, Generator bus and Transmission Node. The LBMP bus and zonal calculation procedures are described in Sections 17.1.1 and 17.1.5 of this Attachment B, respectively. Procedures governing the calculation of LBMPs at Proxy Generator Buses are set forth below in Section 17.1.6 of this Attachment B.

17.1.2.1 General Procedures

17.1.2.1.1 Overview

The ISO shall calculate Real-Time Market LBMPs using the three passes of each RTD run, except as noted below in Section 17.1.2.1.3. A new RTD run will initialize every five minutes and each run will produce prices and schedules for five points in time (the optimization period). Only the prices and schedules determined for the first time point of the optimization period will be binding. Prices and schedules for the other four time points of the optimization period are advisory.

Each RTD run shall, depending on when it occurs during the hour, have a bid optimization horizon of fifty, fifty-five, or sixty minutes beyond the first, or binding, point in time that it addresses. The posting time and the first time point in each RTD run, which establishes binding prices and schedules, will be five minutes apart. The remaining points in time in each optimization period can be either five, ten, or fifteen minutes apart depending on when the run begins within the hour. The points in time in each RTD optimization period are arranged so that they parallel as closely as possible RTC's fifteen minute evaluations.

For example, the RTD run that posts its results at the beginning of an hour ("RTD_0") will initialize at the fifty-fifth minute of the previous hour and produce schedules and prices over a fifty-five minute optimization period. RTD_0 will produce binding prices and schedules for the RTD interval beginning when it posts its results (i.e., at the beginning of the hour) and ending at the first time point in its optimization period (i.e., five minutes after the hour). It will produce advisory prices and schedules for its second time point, which is ten minutes after the first time point in its optimization period, and advisory prices and schedules for its third, fourth and fifth time points, each of which would be fifteen minutes apart. The RTD run that posts its results at

five minutes after the beginning of the hour ("RTD_5") will initialize at the beginning of the hour and produce prices over a fifty minute optimization period. RTD_5 will produce binding prices and schedules for the RTD interval beginning when it posts its results (i.e., at five minutes after the hour) and ending at the first time point in its optimization period (i.e., ten minutes after the hour.) It will produce advisory prices and schedules for its second time point (which is five minutes after the first time point), and advisory prices and schedules for its third, fourth and fifth time points, each of which would be fifteen minutes apart. The RTD run that posts its results at ten minutes after the beginning of the hour ("RTD_{10}") will initialize at five minutes after the beginning of the hour and produce prices over a sixty minute optimization period. RTD_{10} will produce binding prices and schedules for the interval beginning when it posts its results (i.e., at ten minutes after the hour) and ending at the first time point in its optimization period (i.e., fifteen minutes after the hour.) It will produce advisory prices and schedules for its second, third, fourth and fifth time points, each of which would be fifteen minutes after the preceding time point.

Each RTD run shall dispatch Combined Cycle Gas Turbine Generators with Duct-Firing Capability, that have opted for the Limiting Participation Flag, within the operating range determined by the corresponding RTC run, provided however, after an RTD-CAM interval, Combined Cycle Gas Turbine Generators with Duct-Firing Capability, that have opted for the Limiting Participation Flag, will be dispatched within the operating range determined by RTD-CAM for at least 15 minutes, if the RTD-CAM determines the operating zone to be different than the last RTC run.

17.1.2.1.2 Description of the Real-Time Dispatch Process

17.1.2.1.2.1 The First Pass

The first RTD pass consists of a least bid cost, multi-period co-optimized dispatch for Energy, Regulation Service and Operating Reserves that treats all Fixed Block Units that are committed by RTC, or are otherwise instructed to be online or remain online by the ISO as if they were blocked on at their UOL_N or UOL_E, whichever is applicable. Fixed Block Units that do not participate in a Co-located Storage Resource, are capable of being started and meeting Minimum Generation Levels in ten minutes or less, and that have not been committed by RTC, are treated as flexible (i.e. able to be dispatched anywhere between zero (0) MW and their UOL_N or UOL_E, whichever is applicable). The first pass establishes "physical base points" (i.e., real-time Energy schedules) and real-time schedules for Regulation Service and Operating Reserves for the first time point of the optimization period. Physical base points and schedules established for the first time point shall be binding and shall remain in effect until the results of the next run are posted. Physical base points and schedules established for all subsequent time points shall be advisory. The first pass also produces information that is used to calculate the RTD Base Point Signals that the ISO sends to Suppliers.

RTD will consider CSR Scheduling Limits when setting physical base points for Generators that participate as Co-located Storage Resources.

When establishing physical base points, the ISO shall assume that each Generator and Aggregation will move toward the physical base point established during the first pass of the prior RTD run at its specified response rate.

17.1.2.1.2.1.1 Upper and Lower Dispatch Limits for Dispatchable Resources Other Than Intermittent Power Resources That Depend on Wind or Solar Energy as Their Fuel

When setting physical base points for a Dispatchable Resource at the first time point, the ISO shall ensure that they do not fall outside of the bounds established by the Dispatchable Resource's lower and upper dispatch limits. A Dispatchable Resource's dispatch limits shall be determined based on whether it was feasible for it to reach the physical base point calculated by the last RTD run given its: (A) metered output level and metered Energy Level (if applicable) at the time that the RTD run was initialized; (B) response rate; (C) minimum generation level/LOL; (D) USL and LSL (if applicable); and (E) UOL_N or UOL_E, whichever is applicable. If it was feasible for the Dispatchable Resource to reach that base point, then its upper and lower dispatch limits shall reflect the highest and lowest output levels it could achieve over the next RTD interval starting from its previous base point, subject to factors (A) through (E) specified above. If it was not feasible for the Dispatchable Resource to reach that base point, then its upper and lower dispatch limits shall reflect the highest and lowest output levels it could achieve over the next RTD interval, subject to factors (A) through (E) specified above, but instead starting from the feasible output level closest to its previous base point.

When setting physical base points for a Dispatchable Resource at later time points, the ISO shall ensure that they do not fall outside of the bounds established by the Resource's lower and upper dispatch limits for that time point. A Resource's dispatch limits at later time points shall be based on its: (A) dispatch limits from the first time point; (B) response rate; (C) minimum generation level/LOL; (D) Energy Level, USL and LSL (if applicable); and (E) UOL_N or UOL_E, whichever is applicable.

The upper dispatch limit for a Dispatchable Resource at later time points shall be determined by adjusting the upper dispatch limit from the first time point at the Resource's response rate, up to its UOL_N or UOL_E, whichever is applicable, considering Energy Level limitations for ISO-Managed ESRs. The lower dispatch limit for a Dispatchable Resource at later time points shall be determined by adjusting the lower dispatch limit from the first time point at the Resource's response rate, down to its minimum generation level/LOL considering applicable Energy Level limitations for ISO-Managed ESRs, or to a Demand Side Resource's Demand Reduction level.

The RTD Base Point Signals sent to Dispatchable Resources shall be the same as the physical base points determined above.

17.1.2.1.2.1.2 Upper and Lower Dispatch Limits for Intermittent Power Resources That Depend on Wind or Solar Energy as Their Fuel

For all time points of the optimization period, the Lower Dispatch Limit shall be the higher of (a) an Intermittent Power Resource's metered output level at the time that the RTD run was initialized reduced by its response rate, or (b) zero. The Upper Dispatch Limit shall be the Wind and Solar Energy Forecast for that Resource. For Intermittent Power Resources depending on wind as their fuel in commercial operation as of January 1, 2002 with a name plate capacity of 12 MWs or fewer, the Upper and Lower Dispatch Limits shall be the output level specified by the Wind and Solar Energy Forecast.

17.1.2.1.2.1.3. Setting Physical Basepoints for Fixed Generators and Aggregations

When setting physical base points for Self-Committed Fixed Generators and Aggregations in any time point, the ISO shall consider the feasibility of the Resource reaching the output levels that it specified in its self-commitment request for each time point in the RTD

run given: (A) its metered output at the time that the run was initialized; and (B) its response rate.

When setting physical base points for ISO-Committed Fixed Generators and Aggregations in any time point, the ISO shall consider the feasibility of the Resource reaching the output levels scheduled for it by RTC for each time point in the RTD run given: (A) its metered output at the time that the run was initialized; and (B) its response rate.

The RTD Base Point Signals sent to Self-Committed Fixed Generators and Aggregations shall follow the quarter hour operating schedules that those Generators and Aggregations submitted in their real-time self-commitment requests.

The RTD Base Point Signals sent to ISO-Committed Fixed Generators shall follow the quarter hour operating schedules established for those Generators by RTC, regardless of their actual performance. To the extent possible, the ISO shall honor the response rates specified by such Generators when establishing RTD Base Point Signals. If a Self-Committed Fixed Generator's or Aggregation's operating schedule is not feasible based on its real-time self-commitment requests then its RTD Base Point Signals shall be determined using a response rate consistent with the operating schedule changes.

17.1.2.1.2.2 The Second Pass

The second RTD pass consists of a least bid cost, multi-period, co-optimized dispatch for Energy, Regulation Service, and Operating Reserves that treats: (i) all Fast-Start Resources that are committed by RTC; (ii) Fixed Block Units that do not participate in a Co-located Storage Resource, are capable of starting and meeting Minimum Generation Levels in ten minutes, and have not been committed by RTC; and (iii) all Fixed Block Units otherwise instructed to be online or remain online by the ISO, as flexible (i.e., able to be dispatched anywhere between zero

(0) MW and their UOL_N or UOL_E, whichever is applicable), regardless of their minimum run-time status. The dispatch of Generators, including Fast-Start Resources and Fixed Block Units, that participate as Co-located Storage Resources will consider CSR Scheduling Limits. The second pass calculates real-time Energy prices and real-time Shadow Prices for Regulation Service and Operating Reserves that the ISO shall use for settlement purposes pursuant to Section 4, Rate Schedule 15.3, and Rate Schedule 15.4 of this ISO Services Tariff respectively. The ISO will not use schedules for Energy, Regulation Service and Operating Reserves established in the second pass to dispatch Resources.

The upper and lower dispatch limits used for ISO-Committed Fixed and Self-Committed Fixed Resources shall be the same as the physical base points calculated in the first pass.

17.1.2.1.2.2.1 Upper and Lower Dispatch Limits for Dispatchable Resources Other Than Intermittent Power Resources That Depend on Wind or Solar Energy as Their Fuel

The upper dispatch limit for the first time point of the second pass for a Dispatchable Resource shall be the higher of: (A) its upper dispatch limit from the first pass; or (B) its "pricing base point" from the first time point of the prior RTD interval adjusted up within its Dispatchable range for any possible ramping since that pricing base point was issued less the higher of: (i) the physical base point established during the first pass of the RTD immediately prior to the previous RTD minus the Resource's metered output level at the time that the current RTD run was initialized, or (ii) zero.

The lower dispatch limit for the first time point of the second pass for a Dispatchable Resource shall be the lower of: (A) its lower dispatch limit from the first pass; or (B) its "pricing base point" from the first time point of the prior RTD interval adjusted down within its Dispatchable range to account for any possible ramping since that pricing base point was issued

plus the higher of: (i) the Resource's metered output level at the time that the current RTD run was initialized minus the physical base point established during the first pass of the RTD immediately prior to the previous RTD, considering the metered Energy Level if applicable; or (ii) zero.

The upper dispatch limit for the later time points of the second pass for a Dispatchable Resource shall be determined by adjusting its upper dispatch limit from the first time point at the Resource's response rate, up to its UOL_N or UOL_E, whichever is applicable, considering Energy Level limitations for ISO-Managed ESRs. The lower dispatch limit for the later time points of the second pass for a Dispatchable non-Fast-Start Resource shall be determined by adjusting its lower dispatch limit from the first time point at the Resource's response rate, down to its minimum generation level/LOL, considering Energy Level limitations for ISO-Managed ESRs. The lower dispatch limit for the later time points of the second pass for a Fast Start Resource shall be determined by decreasing its lower dispatch limit from the first time point at the Resource's response rate, down to zero.

17.1.2.1.2.2.2 Upper and Lower Dispatch Limits for Intermittent Power Resources That Depend on Wind or Solar Energy as Their Fuel

For the first time point and later time points for Intermittent Power Resources that depend on wind or solar energy as their fuel, the Lower Dispatch Limit shall be zero and the Upper Dispatch Limit shall be the Wind and Solar Energy Forecast for that Resource. For Intermittent Power Resources depending on wind as their fuel in commercial operation as of January 1, 2002 with a name plate capacity of 12 MWs or fewer, the Upper and Lower Dispatch Limits shall be the output level specified by the Wind and Solar Energy Forecast.

17.1.2.1.2.3 The Third Pass

The third RTD pass is reserved for future use.

17.1.2.1.3 Variations in RTD-CAM

When the ISO activates RTD-CAM, the following variations to the rules specified above in Sections 17.1.2.1.1 and 17.1.2.1.2 shall apply.

First, if the ISO enters reserve pickup mode: (i) the ISO will produce prices and schedules for a single ten minute interval (not for a multi-point co-optimization period); (ii) the ISO shall set Regulation Service schedules to zero as described in Rate Schedule 15.3 of this ISO Services Tariff; (iii) the ISO will have discretion to make additional Generator and Aggregations commitments before executing the three RTD passes; and (iv) the ISO will have discretion to allow the RTD Base Point Signal of each Dispatchable Generator or Aggregation to be set to the higher of the Generator's or Aggregation's physical base point or its actual supply level.

Second, if the ISO enters maximum generation pickup mode: (i) the ISO will produce prices and schedules for a single five minute interval (not for a multi-point co-optimization period); (ii) the ISO shall set Regulation Service schedules to zero as described in Rate Schedule 15.3 of this ISO Services Tariff; (iii) the ISO will have discretion to make additional Generator and Aggregation commitments in the affected area before executing the three RTD passes; and (iv) the ISO will have discretion: (a) either to move the RTD Base Point Signal of each Generator and Aggregation within the affected area towards its UOL_E at its emergency response rate or set it at a level equal to its physical base point; (b) either to move the RTD Base Point Signal of each Combined Cycle Gas Turbine Generator with Duct-Firing Capability within the affected area, that has not opted for the Limiting Participation Flag, towards its UOL_E at the normal response rate corresponding to its output level at the time when RTD-CAM was

activated, or to set it at a level equal to that physical base point; and (c) either to move the RTD Base Point Signal of each Combined Cycle Gas Turbine Generator with Duct-Firing Capability within the affected area, that has opted for the Limiting Participation Flag, (1) towards its Participation Limit at the normal response rate corresponding to its output level at the time when RTD-CAM was activated, if the Generator's output level at that time is equal to or below the Participation Limit or (2) to its UOLE at the normal response rate corresponding to its output level at the time when RTD-CAM was activated, if the Generator's output level at that time was above the Participation Limit.

Third, if the ISO enters basepoints ASAP – no commitments mode it will produce prices and schedules for a single five minute interval (not for a multi-point co-optimization period).

Fourth, if the ISO enters basepoints ASAP – commit as needed mode: (i) the ISO will produce price and schedules for a single five minute interval (not for a multi-point co-optimization period); and (ii) the ISO may make additional commitments of Generators and Aggregations that are capable of starting within ten minutes before executing the three RTD passes.

Fifth, and finally, if the ISO enters re-sequencing mode it will solve for a ten-minute optimization period consisting of two five-minute time points.

17.1.2.1.4 The Real-Time Commitment ("RTC") Process and Automated Mitigation

Attachment H of this Services Tariff shall establish automated market power mitigation measures that may affect the calculation of Real-Time LBMPs. To the extent that these measures are implemented they shall be incorporated into the RTC software through the establishment of a second, parallel, commitment evaluation that will assess the impact of the mitigation measures. The first evaluation, referred to as the "RTC evaluation," will determine

the schedules and prices that would result using an original set of offers and Bids before any additional mitigation measures, the necessity for which will be considered in the RTC evaluation, are applied. The second evaluation, referred to as the "RT-AMP" evaluation, will determine the schedules and prices that would result from using the original set of offers and bids as modified by any necessary mitigation measures. Both evaluations will follow the rules governing RTC's operation that are set forth in Section 4 of and this Attachment B to this ISO Services Tariff.

In situations where Attachment H specifies that real-time automated mitigation measures be utilized, the ISO will perform the two parallel RTC evaluations in a manner that enables it to implement mitigation measures one RTC run (i.e., fifteen minutes) in the future. For example, RTC_{15} and $RT\text{-}AMP_{15}$ will perform Resource commitment evaluations simultaneously. $RT\text{-}AMP_{15}$ will then apply the mitigation "impact" test, account for reference bid levels as appropriate and determine which Resources are actually to be mitigated. This information will then be conveyed to RTC_{30} which will make Resource commitments consistent with the application of the mitigation measures (and will thus indirectly be incorporated into future RTD runs).

17.1.3 Day-Ahead LBMP Calculation Procedures

LBMPs in the Day-Ahead Market are calculated using five passes. The first two passes are commitment and dispatch passes; the last three are dispatch only passes.

Pass 1 consists of a least cost commitment and dispatch to meet Bid Load and reliable operation of the NYS Power System that includes Day-Ahead Reliability Units.

It consists of several steps. Step 1A is a complete Security Constrained Unit Commitment ("SCUC") to meet Bid Load. At the end of this step, committed Fast-Start

Resources, Imports, Exports, Virtual Supply, Virtual Load, and non-Fast-Start Resources are dispatched to meet Bid Load. Fast-Start Resources are treated as dispatchable between zero MW and their UOL_N or UOL_E, whichever is applicable. For mitigation purposes, LBMPs are calculated from this dispatch. Following Step 1A, SCUC tests for automated mitigation procedure ("AMP") activation.

If AMP is activated, Step 1B tests to determine if the AMP will be triggered by mitigating offer prices subject to mitigation that exceed the conduct threshold to their respective reference prices. These mitigated offer prices together with all originally submitted offer prices not subject to automatic mitigation are then used to commit generation and dispatch energy to meet Bid Load. This step is another iteration of the SCUC process. At the end of Step 1B, committed Fast-Start Resources, Imports, Exports, Virtual Supply, Virtual Load, and non-Fast-Start Resources are again dispatched to meet Bid Load using the same mitigated or unmitigated Bids used to determine the commitment to meet Bid Load. Fast-Start Resources are treated as dispatchable between zero MW and their UOL_N or UOL_E, whichever is applicable. For mitigation purposes, LBMPs are again calculated from this dispatch. The LBMPs determined at the end of Step 1B are compared to the LBMPs determined at the end of Step 1A to determine the hours and zones in which the impact test is met.

In Step 1C, generation offer prices subject to mitigation that exceed the conduct threshold are mitigated for those hours and zones in which the impact test was met in Step 1B. The mitigated offer prices, together with the original unmitigated offer price of units whose offer prices were not subject to mitigation, or did not trigger the conduct or impact thresholds, are used to commit generation and dispatch energy to meet Bid Load. This step is also a complete iteration of the SCUC process. At the end of Step 1C, committed Fast-Start Resources, Imports,

Exports, virtual supply, virtual load, and non- Fast-Start Resources are again dispatched to meet Bid Load. Fast-Start Resources are treated as dispatchable between zero MW and their UOL_N or UOL_E, whichever is applicable. The dispatch for Generators, including Fast-Start Resources and Fixed Block Units, that participate as Co-located Storage Resources will consider CSR Scheduling Limits. For mitigation purposes, LBMPs are again calculated from this dispatch.

All non-Fast-Start Resources committed in the final step of Pass 1 (which could be either step 1A, 1B, or 1C depending on activation of the AMP) are blocked on at least to minimum generation level in Passes 4 through 6. All Energy Storage Resources and Aggregations dispatched in the final step of Pass 1 (which could be either Step 1A, 1B, or 1C depending on activation of the AMP) are blocked on at the dispatch that was determined in Pass 1 in Passes 2 through 4. The resources required to meet local system reliability are determined in Pass 1.

Pass 2 consists of a least cost commitment and dispatch of Fast-Start Resources, Imports, Exports, and non- Fast-Start Resources to meet forecast Load requirements in excess of Bid Load, considering the Wind and Solar Energy Forecast, that minimizes the cost of incremental Minimum Generation and Start Up Bids, given revenues for Minimum Generation Energy based on LBMPs calculated in Pass 1, and assumes all Fast-Start Resources are dispatchable between zero MW and their UOL_N or UOL_E, whichever is applicable. The dispatch for Generators, including Fast-Start Resources, that participate as Co-located Storage Resources will consider CSR Scheduling Limits. Incremental Import Capacity needed to meet forecast Load requirements is determined in Pass 2. Fixed Block Units committed in this pass are not included in the least cost dispatches of Passes 5 or 6. Non-Fast-Start Resources committed in this step are blocked on at least to minimum generation level in Passes 4 through 6. Intermittent Power

Resources that depend on wind or solar energy as their fuel committed in this pass as a result of the consideration of the Wind and Solar Energy Forecast are not blocked in Passes 5 or 6.

Pass 3 is reserved for future use.

Pass 4 consists of a least cost dispatch to forecast Load. It is not used to set schedules or prices. It is used for operational purposes and provides a dispatch of Fast-Start Resources, Imports, Exports, and non- Fast-Start Resources committed in Passes 1 or 2. Incremental Import Capacity committed in Pass 2 is re-evaluated and may be reduced if no longer required.

Pass 5 consists of a least cost dispatch of Fast-Start Resources, Imports, Exports, Virtual Supply, Virtual Load, and non- Fast-Start Resources committed to meet Bid Load, based where appropriate on offer prices as mitigated in Pass 1. Fast-Start Resources are treated as dispatchable between zero MW and their UOL_N or UOL_E, whichever is applicable. LBMPs used to settle the Day-Ahead Market are calculated from this dispatch. The Shadow Prices used to compute Day-Ahead Market clearing prices for Regulation Service and for Operating Reserves in Rate Schedules 3 and 4 of this ISO Services Tariff are also calculated from this dispatch. Final schedules for all Imports, Exports, Virtual Supply, Virtual Load, and non-Fast-Start Resources in the Day-Ahead Market are calculated from this dispatch.

Pass 6 consists of a least cost dispatch of all Day-Ahead committed Resources, Imports, Exports, Virtual Supply, Virtual Load, based where appropriate on offer prices as mitigated in Pass 1, with the schedules of all Fixed Block Units committed in the final step of Pass 1 blocked on at maximum Capacity. Final Day-Ahead Market schedules are calculated from this dispatch for Fast-Start Resources and Combined Cycle Gas Turbine Generators with Duct-Firing Capability that have opted for the Limiting Participation Flag.

17.1.4 Determination of Transmission Shortage Cost

The applicable Transmission Shortage Cost depends on whether a particular transmission Constraint is associated with a transmission facility or Interface that includes a non-zero constraint reliability margin value. The ISO shall establish constraint reliability margin values for transmission facilities and Interfaces. Non-zero constraint reliability margin values established by the ISO are normally equal to 20 MW. The ISO assigns a non-zero constraint reliability margin value (normally equal to 5 MW) to certain transmission facilities accommodating power flows out of export constrained areas (or "generation pockets") that, as further described below, are subject to a different Transmission Shortage Cost (for purposes of this Section 17.1.4, the aforementioned facilities are hereinafter referred to as "Identified Facilities"). The ISO shall post to its website a list of transmission facilities and Interfaces assigned a constraint reliability margin value other than 20 MW. The list posted by the ISO shall also include Identified Facilities and the applicable constraint reliability margin value assigned to each such facility.

Except for Identified Facilities, when evaluating transmission Constraints associated with transmission facilities and Interfaces assigned a non-zero constraint reliability margin value, SCUC, RTC, and RTD shall include consideration of a six-step demand curve consisting of the following components: (1) a MW value of additional available resource capacity equal to or less than 20% of the applicable constraint reliability margin value, at a cost of $200/MWh; (2) a MW value of additional available resource capacity equal to or less than 40% of the applicable constraint reliability margin value, but greater than 20% of such value, at a cost of $350/MWh; (3) a MW value of additional available resource capacity equal to or less than 60% of the applicable constraint reliability margin value, but greater than 40% of such value, at a cost of

$600/MWh; (4) a MW value of additional available resource capacity equal to or less than 80% of the applicable constraint reliability margin value, but greater than 60% of such value, at a cost of $1,500/MWh; (5) a MW value of additional available resource capacity equal to or less than 100% of the applicable constraint reliability margin value, but greater than 80% of such value, at a cost of $2,500/MWh; and (6) any MW value of additional available resource capacity greater than the applicable constraint reliability margin value, at a cost of $4,000/MWh.

When evaluating transmission Constraints associated with Identified Facilities, SCUC, RTC, and RTD shall include consideration of a two-step demand curve consisting of the following components: (1) a MW value of additional available resource capacity equal to or less than the applicable constraint reliability margin value, at a cost of $100/MWh; and (2) any MW value of additional available resource capacity greater than the applicable constraint reliability margin value, at a cost of $250/MWh.

For transmission facilities and Interfaces assigned a non-zero constraint reliability margin value, the applicable demand curve, as described above, shall be applied in a manner such that it is considered in resolving, collectively, all applicable transmission Constraints associated with a particular transmission facility or Interface rather than applying a distinct demand curve individually to each such transmission Constraint. In the event of redundant transmission Constraints on in-series transmission facilities or parallel transmission facilities, the most limiting of such redundant transmission Constraints shall be deemed binding and utilized for the purposes of determining the applicable Shadow Price for the redundant transmission Constraints at issue. The less limiting of such redundant transmission Constraints on in-series transmission facilities or parallel transmission facilities shall be deemed non-binding and assigned a zero value Shadow Price. The MW value of the additional available resource capacity associated

with each step of the applicable demand curve, as described above, shall be rounded to the nearest whole number.

For transmission facilities and Interfaces with a constraint reliability margin value of zero, the Shadow Price for transmission Constraints associated with such facilities and Interfaces shall not exceed $4,000/MWh. SCUC, RTC, and RTD shall not include consideration of additional available resource capacity provided by a demand curve mechanism for such transmission Constraints.

In evaluating transmission Constraints for transmission facilities and Interfaces with a constraint reliability margin value of zero, the ISO will determine whether sufficient available resource capacity exists to solve each transmission Constraint at its applicable limit. If sufficient available resource capacity does not exist to solve the transmission Constraint at its otherwise applicable limit, the ISO shall increase the applicable limit for such transmission Constraint to an amount achievable by the available resource capacity plus 0.2 MW.

Notwithstanding anything to the contrary herein, in circumstances where the ISO is the "Non-Monitoring RTO" with respect to a transmission Constraint associated with a "Flowgate" subject to "M2M" coordination, the ISO's evaluation of such transmission Constraint in the Real-Time Market shall be consistent with the rules and procedures specified in Section 35.23 of Attachment CC of the ISO OATT. For purposes of this Section 17.1.4, the terms "Non-Monitoring RTO," "Flowgate," and "M2M" shall have the meaning specified in Section 35.2.1 of Attachment CC of the ISO OATT.

The ISO may periodically evaluate the Transmission Shortage Cost to determine whether it is necessary to modify the Transmission Shortage Cost to avoid future operational or reliability problems. The ISO will consult with its Market Monitoring Unit after it conducts this

evaluation. If the ISO determines that it is necessary to modify the Transmission Shortage Cost in order to avoid future operational or reliability problems the resolution of which would otherwise require recurring operator intervention outside normal market scheduling procedures, in order to avoid among other reliability issues, a violation of NERC Interconnection Reliability Operating Limits or System Operating Limits, it may temporarily modify it for a period of up to ninety days, provided however the ISO shall file such change with the Commission pursuant to Section 205 of the Federal Power Act within 45 days of such modification. If circumstances reasonably allow, the ISO will consult with its Market Monitoring Unit, the Business Issues Committee, the Commission, and the PSC before implementing any such modification. In all circumstances, the ISO will: (i) consult with those entities as soon as reasonably possible after implementing a temporary modification and shall explain the reasons for the change; and (ii) notify Market Participants of any temporary modification.

The responsibilities of the ISO and the Market Monitoring Unit in evaluating and modifying the Transmission Shortage Cost, as necessary are addressed in Attachment O, Section 30.4.6.8.1 of this Market Services Tariff ("Market Monitoring Plan").

17.1.5 Zonal LBMP Calculation Method

The computation described in Section 17.1.1 of this Attachment B is at the bus level. An eleven (11) zone model will be used for the LBMP billing related to Loads, except for Energy withdrawals by Eligible Generators for later injection onto the grid. The LBMP for a zone will be a Load weighted average of the Load bus LBMPs in the Load Zone. The Load weights which will sum to unity will be calculated from the load bus MW distribution. Each component of the

LBMP for a zone will be calculated as a Load weighted average of the Load bus LBMP components in the zone. The LBMP for a zone *j* can be written as:

$$\gamma_j^Z = \lambda^R + \gamma_j^{L,Z} + \gamma_j^{C,Z}$$

where:

$\gamma_j^Z =$ LBMP for zone j,

$\gamma_j^{L,Z} = \sum_{i=1}^{n} W_i \gamma_i^L$ is the Marginal Losses Component of the LBMP for zone j;

$\gamma_j^{C,Z} = \sum W_i \gamma_i^L$ is the Congestion Component of the LBMP for zone j;

$n =$ number of Load buses in zone j for which LBMPs are calculated; and

$W_i =$ Load weighting factor for bus i.

The NYISO also calculates and posts zonal LBMP for four (4) external zones for informational purposes only. Settlements for External Transactions are determined using the Proxy Generator Bus LBMP. Each external zonal LBMP is equal to the LBMP of the Proxy Generator Bus associated with that external zone. The table below identifies which Proxy Generator Bus LBMP is used to determine each of the posted external zonal LBMPs.

External Zone	External Zone PTID	Proxy Generator Bus	Proxy Generator Bus PTID
HQ	61844	HQ_GEN_WHEEL	23651
NPX	61845	N.E._GEN_SANDY_POND	24062
OH	61846	O.H._GEN_PROXY	24063
PJM	61847	PJM_GEN_KEYSTONE	24065

Consistent with the ISO Services Tariff**,** LBMPs at Proxy Generator Buses are determined using calculated bus prices as described in this Section 17.1. However, no congestion

costs due to Interface ATC Constraints shall be included for the Champlain Hudson Power Express MTF in either the Day-Ahead or Real-Time Market.

17.1.6 Real Time LBMP Calculation Methods for Proxy Generator Buses, Non-Competitive Proxy Generator Buses and Proxy Generator Buses Associated with Designated Scheduled Lines

17.1.6.1 Definitions

Interface ATC Constraint: An Interface ATC Constraint exists when proposed economic transactions over an Interface between the NYCA and the Control Area with which one or more Proxy Generator Bus(es) are associated would exceed the transfer capability for the Interface or for an associated Proxy Generator Bus.

Interface Ramp Constraint: An Interface Ramp Constraint exists when proposed interchange schedule changes pertaining to an Interface between the NYCA and the Control Area with which one or more Proxy Generator Bus(es) are associated would exceed any Ramp Capacity limit imposed by the ISO for the Interface or for an associated Proxy Generator Bus.

NYCA Ramp Constraint: A NYCA Ramp Constraint exists when proposed interchange schedule changes pertaining to the NYCA as a whole would exceed any Ramp Capacity limits in place for the NYCA as a whole.

Proxy Generator Bus Constraint: Any of an Interface ATC Constraint, an Interface Ramp Constraint, or a NYCA Ramp Constraint (individually and collectively).

External Interface Congestion: The product of: (i) the portion of the Congestion Component of the LBMP at a Proxy Generator Bus that is associated with a Proxy Generator Bus Constraint and (ii) a factor, between zero and 1, calculated pursuant to ISO Procedures.

Proxy Generator Bus Border LBMP: The LBMP at a Proxy Generator Bus minus External Interface Congestion at that Proxy Generator Bus.

Unconstrained RTD LBMP: The LBMP as calculated by RTD less any congestion associated with a Proxy Generator Bus Constraint.

17.1.6.2 General Rules

Transmission Customers and Customers with External Generators and Loads can bid into the LBMP Market or participate in Bilateral Transactions. Those with External Generators may arrange LBMP Market sales and/or Bilateral Transactions with Internal or External Loads and

External Loads may arrange LBMP Market purchases and/or Bilateral Transactions with Internal Generators.

The Generator and Load locations for which LBMPs will be calculated will initially be limited to a pre-defined set of Proxy Generator Buses. LBMPs will be calculated for each Proxy Generator Bus within this limited set. When an Interface with multiple Proxy Generator Buses is constrained, the ISO will apply the constraint to all of the Proxy Generator Buses located at that Interface. Except as set forth in Sections 17.1.6.3 and 17.1.6.4, the NYISO will calculate the three components of LBMP for Transactions at a Proxy Generator Bus as provided in the tables below.

When determining the External Interface Congestion, if any, to apply to determine the LBMP for RTD intervals that bridge two RTC intervals, the NYISO shall use the External Interface Congestion associated with the second (later) RTC interval.

17.1.6.2.1 Pricing rules for Dynamically Scheduled Proxy Generator Buses

The pricing rules for Dynamically Scheduled Proxy Generator Buses are to be determined.

17.1.6.2.2 Pricing rules for Variably Scheduled Proxy Generator Buses

The pricing rules for Variably Scheduled Proxy Generator Buses are provided in the following table.

Rule No.	Proxy Generator Bus Constraint affecting External Schedules at location *a*	Direction of Proxy Generator Bus Constraint	Real-Time Pricing Rule (for location *a*)
1	Unconstrained in RTC_{15}, Rolling RTC and RTD	N/A	Real-Time $LBMP_a$ = RTD $LBMP_a$

Rule No.	Proxy Generator Bus Constraint affecting External Schedules at location *a*	Direction of Proxy Generator Bus Constraint	Real-Time Pricing Rule (for location *a*)
2	The Rolling RTC used to schedule External Transactions in a given 15-minute interval is subject to a Proxy Generator Bus Constraint	Into NYCA or out of NYCA (Import or Export)	Real-Time $LBMP_a$ = RTD $LBMP_a$ + Rolling RTC External Interface $Congestion_a$

17.1.6.2.3 Pricing rules for Proxy Generator Buses that are not Dynamically Scheduled or Variably Scheduled

The pricing rules for Proxy Generator Buses that are not Dynamically Scheduled or Variably Scheduled Proxy Generator Buses are provided in the following table.

Rule No.	Proxy Generator Bus Constraint affecting External Schedules at location *a*	Direction of Proxy Generator Bus Constraint	Real-Time Pricing Rule (for location *a*)
1	Unconstrained in RTC_{15}, Rolling RTC and RTD	N/A	Real-Time $LBMP_a$ = RTD $LBMP_a$
3	RTC_{15} is subject to a Proxy Generator Bus Constraint	Into NYCA or out of NYCA (Import or Export)	Real-Time $LBMP_a$ = RTD $LBMP_a$ + RTC_{15} External Interface $Congestion_a$

17.1.6.3 Rules for Non-Competitive Proxy Generator Buses and Associated Interfaces

Real-Time LBMPs for an Interface that is associated with one or more Non-Competitive Proxy Generator Buses or for a Non-Competitive Proxy Generator Bus shall be determined as provided in the tables below. Non-Competitive Proxy Generator Buses are identified in Section 4.4.4 of the Services Tariff.

17.1.6.3.1 Pricing rules for Non-Competitive, Dynamically Scheduled Proxy Generator Buses

The pricing rules for Non-Competitive, Dynamically Scheduled Proxy Generator Buses are to be determined.

17.1.6.3.2 Pricing rules for Non-Competitive, Variably Scheduled Proxy Generator Buses

The pricing rules for Non-Competitive, Variably Scheduled Proxy Generator Buses are provided in the following table.

Rule No.	Proxy Generator Bus Constraint affecting External Schedules at location *a*	Direction of Proxy Generator Bus Constraint	Real-Time Pricing Rule (for location *a*)
1	Unconstrained in RTC_{15}, Rolling RTC and RTD	N/A	Real-Time $LBMP_a$ = RTD $LBMP_a$
4	The Rolling RTC used to schedule External Transactions in a given 15-minute interval is subject to an Interface ATC* or Interface RampConstraint	Into NYCA (Import)	If Rolling RTC Proxy Generator Bus $LBMP_a > 0$, then Real-Time $LBMP_a$ = RTD $LBMP_a$ + Rolling RTC External Interface $Congestion_a$ Otherwise, Real-Time $LBMP_a$ = Minimum of (i) RTD $LBMP_a$ and (ii) zero
5	The Rolling RTC used to schedule External Transactions in a given 15-minute interval is subject to an Interface ATC* or Interface Ramp Constraint	Out of NYCA (Export)	If Rolling RTC Proxy Generator Bus $LBMP_a < 0$, then Real-Time $LBMP_a$ = RTD $LBMP_a$ + Rolling RTC External Interface $Congestion_a$ Otherwise, Real-Time $LBMP_a$ = RTD $LBMP_a$

* However, no congestion costs due to Interface ATC Constraints shall be included for the Champlain Hudson Power Express MTF.

17.1.6.3.3 Pricing rules for Non-Competitive Proxy Generator Buses that are not Dynamically Scheduled or Variably Scheduled Proxy Generator Buses

The pricing rules for Non-Competitive Proxy Generator Buses that are not Dynamically Scheduled or Variably Scheduled Proxy Generator Buses are provided in the following table.

Rule No.	Proxy Generator Bus Constraint affecting External Schedules at location *a*	Direction of Proxy Generator Bus Constraint	Real-Time Pricing Rule (for location *a*)
1	Unconstrained in RTC_{15}, Rolling RTC and RTD	N/A	Real-Time $LBMP_a$ = RTD $LBMP_a$
6	RTC_{15} is subject to an Interface ATC or Interface Ramp Constraint	Into NYCA (Import)	If RTC_{15} Proxy Generator Bus $LBMP_a > 0$, then Real-Time $LBMP_a$ = RTD $LBMP_a$ + RTC_{15} External Interface $Congestion_a$ Otherwise, Real-Time $LBMP_a$ = Minimum of (i) RTD $LBMP_a$ and (ii) zero
7	RTC_{15} is subject to an Interface ATC or Interface Ramp Constraint	Out of NYCA (Export)	If RTC_{15} Proxy Generator Bus $LBMP_a < 0$, then Real-Time $LBMP_a$ = RTD $LBMP_a$ + RTC_{15} External Interface $Congestion_a$ Otherwise, Real-Time $LBMP_a$ = RTD $LBMP_a$

17.1.6.4 Special Pricing Rules for Proxy Generator Buses Associated with Designated Scheduled Lines

Real-Time LBMPs for the Proxy Generator Buses associated with designated Scheduled Lines shall be determined as provided in the tables below. The Proxy Generator Buses that are associated with designated Scheduled Lines are identified in Section 4.4.4 of the Services Tariff.

17.1.6.4.1 Pricing rules for Dynamically Scheduled Proxy Generator Buses that are associated with Designated Scheduled Lines

The pricing rules for Dynamically Scheduled Proxy Generator Buses that are associated with designated Scheduled Lines are to be determined.

17.1.6.4.2 Pricing rules for Variably Scheduled Proxy Generator Buses that are associated with Designated Scheduled Lines

The pricing rules for Variably Scheduled Proxy Generator Buses that are associated with designated Scheduled Lines are provided in the following table.

Rule No.	Proxy Generator Bus Constraint affecting External Schedules at location *a*	Direction of Proxy Generator Bus Constraint	Real-Time Pricing Rule (for location *a*)
1	Unconstrained in RTC_{15}, Rolling RTC and RTD	N/A	Real-Time $LBMP_a$ = RTD $LBMP_a$
4	The Rolling RTC used to schedule External Transactions in a given 15-minute interval is subject to an Interface ATC Constraint	Into NYCA (Import)	If Rolling RTC Proxy Generator Bus $LBMP_a > 0$, then Real-Time $LBMP_a$ = RTD $LBMP_a$ + Rolling RTC External Interface $Congestion_a$ Otherwise, Real-Time $LBMP_a$ = Minimum of (i) RTD $LBMP_a$ and (ii) zero
5	The Rolling RTC used to schedule External Transactions in a given 15-minute interval is subject to an Interface ATC Constraint	Out of NYCA (Export)	If Rolling RTC Proxy Generator Bus $LBMP_a < 0$, then Real-Time $LBMP_a$ = RTD $LBMP_a$ + Rolling RTC External Interface $Congestion_a$ Otherwise, Real-Time $LBMP_a$ = RTD $LBMP_a$)

17.1.6.4.3 Pricing rules for Proxy Generator Buses that are associated with Designated Scheduled Lines that are not Dynamically Scheduled or Variably Scheduled Proxy Generator Buses

The pricing rules for Proxy Generator Buses that are associated with designated Scheduled Lines that are not Dynamically Scheduled or Variably Scheduled Proxy Generator Buses, are provided in the following table.

Rule No.	Proxy Generator Bus Constraint affecting External Schedules at location *a*	Direction of Proxy Generator Bus Constraint	Real-Time Pricing Rule (for location *a*)
1	Unconstrained in RTC_{15}, Rolling RTC and RTD	N/A	Real-Time $LBMP_a$ = RTD $LBMP_a$
6	RTC_{15} is subject to an Interface ATC Constraint	Into NYCA (Import)	If RTC_{15} Proxy Generator Bus $LBMP_a > 0$, then Real-Time $LBMP_a$ = RTD $LBMP_a$ + RTC_{15} External Interface $Congestion_a$ Otherwise, Real-Time $LBMP_a$ = Minimum of (i) RTD $LBMP_a$ and (ii) zero

Rule No.	Proxy Generator Bus Constraint affecting External Schedules at location *a*	Direction of Proxy Generator Bus Constraint	Real-Time Pricing Rule (for location *a*)
7	RTC_{15} is subject to an Interface ATC Constraint	Out of NYCA (Export)	If RTC_{15} Proxy Generator Bus $LBMP_a < 0$, then Real-Time $LBMP_a$ = RTD $LBMP_a$ + RTC_{15} External Interface $Congestion_a$ Otherwise, Real-Time $LBMP_a$ = RTD $LBMP_a$

17.1.6.5 Method of Calculating Marginal Loss and Congestion Components of Real-Time LBMP at Non-Competitive Proxy Generator Buses and Proxy Generator Buses that are Subject to the Special Pricing Rule for Designated Scheduled Lines

Under the conditions specified below, the Marginal Losses Component and the Congestion Component of the Real-Time LBMP, calculated pursuant to the preceding paragraphs in Sections 17.1.6.3 and 17.1.6.4, shall be constructed as follows:

When the Real-Time LBMP is set to zero and that zero price was not the result of using the RTD, RTC or SCUC-determined LBMP;

$$Marginal\ Losses\ Component\ of\ the\ Real\text{-}Time\ LBMP = Losses_{RTD\ PROXY\ GENERATOR\ BUS}$$

and

$$Congestion\ Component\ of\ the\ Real\text{-}Time\ LBMP = -\left(Energy_{RTD\ REF\ BUS} + Losses_{RTD\ PROXY\ GENERATOR\ BUS}\right)$$

where:

$Energy_{RTD\ REF\ BUS}$ = The marginal Bid cost of providing Energy at the reference Bus, as calculated by RTD for that 5-minute interval; and

$Losses_{RTD\ PROXY\ GENERATOR\ BUS}$ = The Marginal Losses Component of the LBMP as calculated by RTD for that 5-minute interval at the Non-Competitive Proxy Generator Bus or Proxy Generator Bus associated with a designated Scheduled Line.

17.2 Accounting For Transmission Losses

17.2.1 Charges

Subject to Attachment K to the ISO OATT, the ISO shall charge all Transmission Customers for transmission system losses based on the marginal cost of losses on either a bus (including a Transmission Node) or zonal basis, described below.

17.2.1.1 Loss Model

The ISO's RTD software will use a power flow model and penalty factors to estimate losses incurred in performing generation dispatch (including dispatch of DER Aggregations) and billing functions for losses.

17.2.1.2 Residual Loss Payment

The ISO will determine the difference between the payments by Transmission Customers for losses and the payments to Suppliers for losses associated with all Transactions (LBMP Market or Transmission Service under Parts 3, 4 and 5 of the ISO OATT) for both the Day-Ahead and Real-Time Markets. The accounting for losses at the margin may result in the collection of more revenue than is required to compensate Generators and Aggregations for the Energy they produced to supply the actual losses in the system. This over collection is termed residual loss payments. The ISO shall calculate residual loss payments revenue on an hourly basis and will credit them against the ISO's Residual Adjustment (See Rate Schedule 1 of the ISO OATT).

17.2.2 Computation of Residual Loss Payments

17.2.2.1 Marginal Losses Component LBMP

The ISO shall utilize the Marginal Losses Component of the LBMP on an Internal bus, an External bus, or a zone basis for computing the marginal contribution of each Transaction to the system losses. The computation of these quantities is described in this Attachment.

17.2.2.1.1 Marginal Losses Component Day-Ahead

The ISO shall utilize the Marginal Losses Component computed by SCUC for computing the marginal contributions of each Transaction in the Day-Ahead Market.

17.2.2.1.2 Marginal Losses Component Real -Time

The ISO shall utilize the Marginal Losses Component calculated by the (i) RTD programs in most cases; or, (ii) during intervals when the conditions specified in Part 17.1 of this Attachment B exist at Proxy Generator Buses, the RTC program, for computing the Marginal Losses Component associated with each Transaction scheduled in the Real-Time Market (or deviations from Transactions scheduled in the Day-Ahead Market). The computations will be performed on an RTD-interval basis and aggregated to an hourly total.

17.2.2.2 Payments and Charges

Payments and charges to reflect the impact of Energy supplied (or withdrawn by Withdrawal-Eligible Generators) by each Generator and Aggregation, consumed by each Load, or transmitted by each Transmission Customer on the Marginal Losses Component shall be determined as follows. Each of these payments or charges may be negative.

17.2.2.3 Day-Ahead Payments and Charges

As part of the LBMP paid to all Suppliers scheduled Day-Ahead to provide Energy to the LBMP Market, the ISO shall pay each such Supplier the product of: (a) the injection scheduled

Day-Ahead from each of that Supplier's Generators or Aggregations in each hour, in MWh; and (b) the Marginal Losses Component of the Day-Ahead LBMP at each of those Generators' buses or Aggregation's Transmission Nodes, in $/MWh.

As part of the LBMP charged to all LSEs scheduled Day-Ahead to purchase Energy from the LBMP Market, the ISO shall charge each such LSE the product of: (a) the withdrawal scheduled Day-Ahead in each Load Zone by that LSE in each hour, in MWh; and (b) the Marginal Losses Component of the Day-Ahead LBMP in that Load Zone, in $/MWh.

As part of the TUC charged to all Transmission Customers whose Transmission Service has been scheduled Day-Ahead, the ISO shall charge each such Transmission Customer the product of: (a) the amount of Energy scheduled Day-Ahead to be injected and withdrawn by that Transmission Customer in each hour, in MWh; and (b) the Marginal Losses Component of the Day-Ahead LBMP at the Point of Delivery (*i.e.*, Load Zone in which Energy is scheduled to be withdrawn or the bus where Energy is scheduled to be withdrawn if the Energy is scheduled to be withdrawn at a location outside the NYCA), minus the Marginal Losses Component of the Day-Ahead LBMP at the Point of Receipt, in $/MWh.

17.2.2.4 Real-Time Payments and Charges

As part of the LBMP paid to all Suppliers providing Energy to the Real-Time LBMP Market, the ISO shall pay each such Supplier the product of: (a) the amount of Energy actually injected by each of that Supplier's Generators or Aggregations in each hour (to the extent that actual injections do not exceed the AGC or RTD Base Points Signals sent to that Supplier for those Generators plus any Compensable Overgeneration payable pursuant to ISO Procedures), minus the amount of Energy each of those Generators or Aggregations was scheduled Day-Ahead to inject in that hour, in MWh; and (b) the loss component of the Real-Time LBMP at each of those Generator's buses or Aggregation's Transmission Nodes, in $/MWh.

As part of the LBMP charged to all LSEs that purchase Energy from the LBMP Market, the ISO shall charge each such LSE the product of (a) the Actual Energy Withdrawals by that LSE in each Load Zone in each hour, minus the Energy withdrawal scheduled Day-Ahead in that Load Zone by that LSE for that hour, in MWh; and (b) the Marginal Losses Component of the Real-Time LBMP in that Load Zone, in $MWh.

As part of the TUC charged to all Transmission Customers whose Transmission Service was scheduled after the determination of the Day-Ahead schedule, or who schedule additional Transmission Service after the determination of the Day-Ahead schedule, the ISO shall charge each such Transmission Customer the product of: (a) Actual Energy Withdrawals scheduled RTD in each hour, minus the amount of Energy scheduled Day-Ahead to be withdrawn by that Transmission Customer in that hour, in MWh; and (b) the Marginal Losses Component of the Real-Time LBMP at the Point of Delivery (i.e., the Load Zone in which Energy is scheduled to be withdrawn or the External bus where Energy is scheduled to be withdrawn if Energy is scheduled to be withdrawn at a location outside the NYCA), minus the Marginal Losses Component of the Real-Time LBMP at the Point of Receipt, in $MWh.

As part of the LBMP paid to all Suppliers providing an amount of Energy that differs from the amount of Energy those Suppliers were scheduled by RTD to provide in an hour in association with Bilateral Transactions, the ISO shall pay each such Supplier the product of: (a) the amount of Energy actually injected by each of that Supplier's Generators and/or Aggregation in each hour (to the extent that actual injections do not exceed the AGC or RTD Base Points Signals sent to that Supplier for those Generators or Aggregations plus any Compensable Overgeneration payable pursuant to ISO Procedures) minus the amount of Energy each of those Generators or Aggregations was scheduled by RTD to provide in that hour in association with

Bilateral Transactions, in MWh; and (b) the Marginal Losses Component of the Real-Time LBMP at each of those Generators' buses, or Aggregation's Transmission Node in $/MWh.

As part of the LBMP charged to all LSEs consuming an amount of Energy that deviates from the amount of Energy those LSEs were scheduled by RTD to consume in an hour in association with Bilateral Transactions, the ISO shall charge each such LSE the product of: (a) the Actual Energy Withdrawals by that LSE in each Load Zone in each hour, minus the Energy withdrawal scheduled by RTD in that Load Zone by that LSE for that hour in association with Bilateral Transactions, in MWh; and (b) the Marginal Losses Component of the Real-Time LBMP in that Load Zone, in $/MWh.

17.3 Bilateral Transaction Bidding, Transmission Service, Schedules and Curtailment

All Transmission Customers and interested entities should refer to Attachment J, Section 16.3 of the ISO OATT for all information related to Transmission Service, Schedules and Curtailment.

17.4 Sale and Award Of Transmission Congestion Contracts ("TCCs")

All Transmission Customers and all applicants seeking to become Transmission Customers should refer to Attachment M of the ISO OATT for all information related to the sale and award of TCCs.

17.5 Congestion Settlements Related To the Day-Ahead Market and TCC Auction Settlements

See Attachment N of the ISO OATT for provisions regarding the Congestion settlements related to the Day-Ahead Market and the settlements related to Centralized TCC Auctions and Reconfiguration Auctions.

18 Attachment C -Formulas For Determining Bid Production Cost Guarantee Payments

18.1 Introduction

Seven Bid Production Cost Guarantee (BPCG) payments for eligible Suppliers are described in this attachment: (i) a Day-Ahead BPCG for Generators; (ii) a Day-Ahead BPCG for Imports; (iii) a real-time BPCG for Generators and Aggregations in RTD intervals other than Supplemental Event Intervals; (iv) a BPCG for Generators and Aggregations for Supplemental Event Intervals; (v) a real-time BPCG for Imports; (vi) a BPCG for long start-up time Generators (i.e., Generators that cannot be scheduled by SCUC to start up in time for the next Dispatch Day) whose start is aborted by the ISO prior to their dispatch; and (vii) a Special Case Resources BPCG. Suppliers shall be eligible for these payments in accordance with the eligibility requirements and formulas established in this Attachment C.

The Bid Production Cost guarantee payments described in this Attachment C are each calculated and paid independently from each other. A Customer's eligibility to receive one type of Bid Production Cost guarantee payment shall have no impact on the Customer's eligibility to be considered to receive another type of Bid Production Cost guarantee payment, in accordance with the rule set forth in this Attachment C.

18.2 Day-Ahead BPCG For Generators and Aggregations

18.2.1 Eligibility to Receive a Day-Ahead BPCG for Generators and Aggregations

18.2.1.1 Eligibility.

A Supplier that bids on behalf of an ISO-Committed Fixed Generator or an ISO Committed Flexible Generator or an ISO-Committed Flexible Aggregation that is committed by the ISO in the Day-Ahead Market shall be eligible to receive a Day-Ahead Bid Production Cost guarantee payment. Energy Storage Resources and Aggregations comprised entirely of Energy Storage Resources that satisfy this eligibility criteria shall be eligible to receive a Day-Ahead Bid Production Cost guarantee payment regardless of whether the Resource Self-Manages its Energy Level.

18.2.1.2 Non-Eligibility (includes both partial and complete exclusions).

Notwithstanding Section 18.2.1.1, a Supplier that bids on behalf of an ISO-Committed Fixed Generator or an ISO-Committed Flexible Generator, or an ISO-Committed Flexible Aggregation, that is committed by the ISO in the Day-Ahead Market shall not be eligible to receive a Day-Ahead Bid Production Cost guarantee payment if that Generator or Aggregation has been committed in the Day-Ahead Market for any other hour of the day as a result of a Self-Committed Fixed or Self-Committed Flexible bid.

Notwithstanding Section 18.2.1.1, Incremental Energy Bid costs and Minimum Generation Bids that exceed $1,000/MWh are only eligible for inclusion in a Day-Ahead Bid Production Cost guarantee payment in accordance with Sections 21.4.1 and 23.7 of this ISO Services Tariff.

18.2.2 Formulas for Determining Day-Ahead BPCG for Generators and Aggregations

18.2.2.1 Applicable Formula. A Supplier's BPCG for Generator or Aggregation g, shall be as follows:

Day-Ahead Bid Production Cost Guarantee for Generator g or Aggregation g =

$$Max\left[\sum_{h=1}^{N}\left(\int_{MGH_{gh}^{DA}}^{EH_{gh}^{DA}} C_{gh}^{DA} + MGC_{gh}^{DA}MGH_{gh}^{DA} + SUC_{gh}^{DA}NSUH_{gh}^{DA} - LBMP_{gh}^{DA}EH_{gh}^{DA} - NASR_{gh}^{DA}\right), 0\right]$$

18.2.2.2 Variable Definitions. The terms used in this Section 18.2.2 shall be defined as follows:

$Supplier_g$ = Generator *g* or Aggregation *g*;

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

EH_{gh}^{DA} = Energy scheduled Day-Ahead to be provided by Supplier *g* or withdrawn by Supplier g, which is eligible to withdraw Energy,in hour *h* expressed in terms of MWh;

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

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

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

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

minimum run time reflected in the accepted Bid for the hour in which it was scheduled to start on the day before the Dispatch Day;

SUC_{gh}^{DA} = Start-Up Bid by Supplier *g* in hour *h,* or when applicable the mitigated Start-Up Bid for Supplier *g,* in hour *h* in the Day-Ahead Market expressed in terms of $/start; *provided, however*, that the Start-Up Bid for Supplier *g* in hour *h* or, when applicable, the mitigated Start-Up Bid, for Supplier *g* in hour *h*, may be subject to *pro rata* reduction in accordance with the rules set forth in Section 18.12 of this Attachment C. Bases for *pro rata* reduction include, but are not limited to, failure to be scheduled, and to operate in real-time to produce, in each hour, the MWh specified in the accepted Minimum Generation Bid that was submitted for the first hour of Generator g's Day-Ahead or SRE schedule, and failure to operate for the minimum run time specified in the Bid submitted for the first hour of Supplier *g*'s Day-Ahead or SRE schedule.

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

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

$NSUH_{gh}^{DA}$ = number of times Supplier g is scheduled Day-Ahead to start up in hour h;

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

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

Day-Ahead Bid to provide Spinning Reserve and synchronized 30-Minute Reserve in that hour.

18.3 Day-Ahead BPCG For Imports

18.3.1 Eligibility to Receive a Day-Ahead BPCG for Imports

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

18.3.2 BPCG Calculated by Transaction ID

For purposes of calculating a Day-Ahead Bid Production Cost guarantee payment for an Import under this Section 18.3, the ISO shall treat the Import as being from a single Resource for all hours of the Day-Ahead Market day in which the same Transaction ID is used, and the ISO shall treat the Import as being from a different Resource for all hours of the Day-Ahead Market day in which a different Transaction ID is used.

18.3.3 Formula for Determining Day-Ahead BPCG for Imports

Day-Ahead Bid Production Cost guarantee for Import t by Supplier =

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

Where;

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

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

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

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

18.4 Real-Time BPCG For Generators and Aggregations In RTD Intervals Other Than Supplemental Event Intervals

18.4.1 Eligibility for Receiving Real-Time BPCG for Generators and Aggregations in RTD Intervals Other Than Supplemental Event Intervals

18.4.1.1 Eligibility.

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

18.4.1.1.1 an ISO-Committed Flexible Generator or an ISO-Committed Fixed Generator that is committed by the ISO in the Real-Time Market; or

18.4.1.1.2 a Self-Committed Flexible Generator if the Generator's minimum operating level does not exceed its Day-Ahead schedule at any point during the Dispatch Day; or

18.4.1.1.3 a Generator or Aggregation committed via SRE, or committed or dispatched by the ISO as Out-of-Merit generation to ensure NYCA or local system reliability for the hours of the day that it is committed via SRE or is committed or dispatched by the ISO as Out-of-Merit generation to meet NYCA or local system reliability without regard to the Bid mode(s) employed during the Dispatch Day, except as provided in Sections 18.4.2 and 18.12, below.

18.4.1.1.4 an ISO-Committed Flexible Aggregation comprised entirely of Energy Storage Resources that Self-Manages its Energy Level.

18.4.1.2 Non-Eligibility (includes both partial and complete exclusions).

18.4.1.2.1 Notwithstanding Section 18.4.1.1, a Supplier that bids on behalf of an ISO-Committed Fixed Generator or an ISO-Committed Fixed Aggregation or an ISO-Committed Flexible Generator that is committed by the ISO in the Real-Time Market shall not be eligible to

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

18.4.1.2.2 Notwithstanding Section 18.4.1.1, Incremental Energy Bid costs and Minimum Generation Bids that exceed $1,000/MWh are only eligible for inclusion in a real-time Bid Production Cost guarantee payment for intervals other than Supplemental Event Intervals, in accordance with Sections 21.4.1 and 23.7 of this ISO Services Tariff.

18.4.1.2.3 Notwithstanding Section 18.4.1.1, an Energy Storage Resource or Aggregation comprised entirely of Energy Storage Resources with a ISO-Managed Energy Level for any hour of the Real-Time Market day shall not be eligible to receive a real-time Bid Production Cost guarantee payment for that day, provided however, an Energy Storage Resource or Aggregation comprised entirely of Energy Storage Resources shall be eligible for a real-time

Bid Production Cost guarantee payment in accordance with Section 18.4.1.1.3 of this ISO Services Tariff regardless of whether the Energy Level is ISO-Managed.

18.4.1.2.4 Notwithstanding Section 18.4.1.1, Energy Storage Resources and Aggregations shall not be eligible to receive a real-time Bid Production Cost guarantee payment for a day if such Resources' Real-Time Market Bids for any hour of that day do not permit the Resource to receive a schedule of zero MW. However, such Resources shall be eligible for a real-time Bid Production Cost guarantee payment in accordance with Section 18.4.1.1.3 of this ISO Services Tariff.

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

Real-Time Bid Production Cost Guarantee for Supplier g, which is not an Energy Storage Resource or an Aggregation that contains Energy Storage Resource(s) =

$$Max\left[\left(\sum_{i\in M}\left(\left(\int_{max\left(EI_{gi}^{DA},MGI_{gi}^{RT}\right)}^{max\left(EI_{gi}^{RT},MGI_{gi}^{RT}\right)} C_{gi}^{RT} + MGC_{gi}^{RT} * \left(MGI_{gi}^{RT} - MGI_{gi}^{DA}\right) - LBMP_{gi}^{RT} * \left(EI_{gi}^{RT} - EI_{gi}^{DA}\right)\right) * \frac{S_i}{3600}\right)\right) - \left(NASR_{gi}^{TOT} - NASR_{gi}^{DA}\right) - RRAP_{gi} + RRAC_{gi} + \sum_{j\in L} SUC_{gj}^{RT} * \left(NSUI_{gj}^{RT} - NSUI_{gj}^{DA}\right)\right), 0\right]$$

Real-Time Bid Production Cost Guarantee for Supplier g, which is an Energy Storage Resource or an Aggregation that contains Energy Storage Resource(s) =

$$Max\left(0, \sum_{i\in M}\left(InjBPCG_{gi} + WthBPCG_{gi}\right)\right)$$

where, when an Energy Storage Resource or an Aggregation that contains Energy Storage Resource(s) has a real-time schedule to inject Energy:

$$InjBPCG_{gi} = \left(\left(\int_{max\left(EI_{gi}^{DA},0\right)}^{EI_{gi}^{RT}} C_{gi}^{RT} - LBMP_{gi}^{RT} * \left(EI_{gi}^{RT} - max\left(EI_{gi}^{DA},0\right) \right) \right) * \frac{S_i}{3600} \right)$$

$$- \left(NASR_{gi}^{TOT} - NASR_{gi}^{DA} \right) - RRAP_{gi} + RRAC_{gi}$$

and, when an Energy Storage Resource or an Aggregation that contains Energy Storage Resource(s) has a real-time schedule to withdraw Energy =

$$WthBPCG_{gi} = \left(\left(\int_{min\left(EI_{gi}^{DA},0\right)}^{EI_{gi}^{RT}} C_{gi}^{RT} - LBMP_{gi}^{RT} * \left(EI_{gi}^{RT} - min\left(EI_{gi}^{DA},0\right) \right) \right) * \frac{S_i}{3600} \right)$$

$$- \left(NASR_{gi}^{TOT} - NASR_{gi}^{DA} \right) - RRAP_{gi} + RRAC_{gi}$$

where:

$Supplier_g$ = Generator g or Aggregation g;

S_i = number of seconds in RTD interval i;

C_{gi}^{RT} = Bid cost submitted by Supplier g, or when applicable the mitigated Bid cost for Supplier g, in the RTD for the hour that includes RTD interval i expressed in terms of $/MWh, except in intervals in which the dispatch of the Supplier is constrained by its downward ramp rate for that interval, unless that Supplier was scheduled to provide Regulation Service in that interval and its RTD basepoint was less than its AGC basepoint, and except in hours in which the NYISO has increased Supplier g's minimum operating level, either (i) at the Supplier's request including through an adjustment to the Resource's self-commitment schedule, or (ii) in order to reconcile the ISO's dispatch with the Supplier's actual output or to address reliability concerns that arise because the Supplier is not following Base Point Signals, in which case C_{gi}^{RT} shall be deemed to be zero;

MGI_{gi}^{RT} = metered Energy provided by minimum generation segment of Supplier g in RTD interval i expressed in terms of MW;

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

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

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

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

provided, however,

(i) the Start-Up Bid shall be deemed to be zero for (1) Self-Committed Fixed and Self-Committed Flexible Suppliers, (2) Suppliers that are economically committed by RTC or RTD that have 10-minute start-up times that are not synchronized and producing Energy within 20 minutes after their scheduled start time, and (3) Suppliers that are economically committed by RTC that have greater than 10-minute start-up times that are not synchronized and producing Energy within 45 minutes after their scheduled start time;

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

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

(iv) the real-time Start-Up Bid for Supplier g for hour j or, when applicable, the mitigated real-time Start-Up Bid, for Supplier g for hour j, may be subject to *pro rata* reduction in accordance with the rules set forth in Section 18.12 of this Attachment C. Bases for *pro rata* reduction include, but are not limited to, failure to be scheduled and operate in real-time to produce, in each hour, the MWh specified in the accepted Minimum Generation Bid that was submitted for the first hour of Supplier g's Day-Ahead or SRE schedule, and failure to operate for the minimum run time specified in the Bid submitted for the first hour of Supplier g's Day-Ahead or SRE schedule; and

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

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

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

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

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

(i) Supplemental Event Intervals (which are addressed separately in Section 18.5 below);

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

L = the set of all hours in the Dispatch Day

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

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

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

EI_{gi}^{DA} = Energy scheduled in the Day-Ahead Market to be provided or withdrawn by Supplier g in the hour that includes RTD interval i expressed in terms

of MW;

$RTSen_{ig}$ = Real-time Energy scheduled for Supplier g in interval i, and calculated as the arithmetic average of the 6-second AGC Base Point Signals sent to Supplier g during the course of interval i expressed in terms of MW;

AE_{ig} = either, (1) when scheduled to withdraw, average Energy injections plus average Demand Reductions minus average Energy withdrawals by Supplier g in interval i but not more than $RTSen_{ig}$ plus any Compensable Overgeneration expressed in terms of MW; or (2) otherwise, average Energy injections plus average Demand Reductions minus average Energy withdrawals by Generator g in interval i expressed in terms of MW;

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

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

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

$RRAP_{gi}$ = Regulation Revenue Adjustment Payment for Supplier g in RTD interval i expressed in terms of $.

$RRAC_{gi}$ = Regulation Revenue Adjustment Charge for Supplier g in RTD interval i expressed in terms of $.

18.4.3 Bids Used For Intervals at the End of the Hour

For RTD intervals in an hour that start 55 minutes or later after the start of that hour, a Bid used to determine real-time BPCG in Section 18.4.2 will be the Bid for the next hour in accordance with ISO Procedures. For RTD-CAM intervals in an hour that start 50 minutes or later after the start of that hour, a Bid used to determine real-time BPCG in Section 18.4.2 will be the Bid for the next hour, in accordance with ISO Procedures.

18.5 BPCG For Generators and Aggregations In Supplemental Event Intervals

18.5.1 Eligibility for BPCG for Generators and Aggregations in Supplemental Event Intervals

18.5.1.1 Eligibility

For intervals in which the ISO has called a large event reserve pick-up, as described in Section 4.4.4.1.1 of this ISO Services Tariff, or an emergency under Section 4.4.4.1.2 of this ISO Services Tariff, any Supplier who meets the eligibility requirements for a real-time Bid Production Cost guarantee payment described in subsection 18.4.1.1 of this Attachment C, shall be eligible to receive a BPCG under this Section 18.5.

18.5.1.2 Non-Eligibility (includes both partial and complete exclusions)

(A) Notwithstanding subsection 18.5.1.1, a Supplier shall not be eligible to receive a Bid Production Cost guarantee payment for Supplemental Event Intervals if the Supplier is not eligible for a real-time Bid Production Cost guarantee payment for the reasons described in Section 18.4.1.2 of this Attachment C.

(B) Notwithstanding subsection 18.5.1.1, Incremental Energy Bid costs and Minimum Generation Bids that exceed $1,000/MWh are only eligible for inclusion in a real-time Bid Production Cost guarantee payment for Supplemental Event Intervals, in accordance with Sections 21.4.1 and 23.7 of this ISO Services Tariff.

18.5.1.3 Additional Eligibility

Notwithstanding Section 18.5.1.2(A), a Supplier shall be eligible to receive a Bid Production Cost guarantee payment for a Generator or Aggregation providing energy during

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

18.5.2 Formula for Determining BPCG for Generators and Aggregations in Supplemental Event Intervals

Real-Time Bid Production Cost Guarantee Payment for Generator or Aggregation g, which is not an Energy Storage Resource or an Aggregation that contains Energy Storage Resource(s) =

$$\sum_{i \in P} \left(\max \left(\begin{array}{c} \left(\int_{max\left(EI_{gi}^{DA}, MGI_{gi}^{RT}\right)}^{max\left(EI_{gi}^{RT}, MGI_{gi}^{RT}\right)} C_{gi}^{RT} + MGC_{gi}^{RT} * \left(MGI_{gi}^{RT} - MGI_{gi}^{DA}\right) \right) * \frac{S_i}{3600} \\ - LBMP_{gi}^{RT} * \left(EI_{gi}^{RT} - EI_{gi}^{DA}\right) - \left(NASR_{gi}^{TOT} - NASR_{gi}^{DA}\right) - RRAP_{gi} + RRAC_{gi} \end{array} \right), 0 \right)$$

Real-Time Bid Production Cost Guarantee for Supplier g, which is an Energy Storage Resource or an Aggregation that contains Energy Storage Resource(s) =

$$Max\left(0, \sum_{i \in P} \left(InjBPCG_{gi} + WthBPCG_{gi}\right)\right)$$

where, when an Energy Storage Resource or an Aggregation that contains Energy Storage Resource(s) has a real-time schedule to inject Energy:

$$InjBPCG_{gi} = \left(\left(\int_{max\left(EI_{gi}^{DA}, 0\right)}^{EI_{gi}^{RT}} C_{gi}^{RT} - LBMP_{gi}^{RT} * \left(EI_{gi}^{RT} - max\left(EI_{gi}^{DA}, 0\right)\right) \right) * \frac{S_i}{3600} \right)$$

$$- \left(NASR_{gi}^{TOT} - NASR_{gi}^{DA}\right) - RRAP_{gi} + RRAC_{gi}$$

and, when an Energy Storage Resource or an Aggregation that contains Energy Storage Resource(s) has a real-time schedule to withdraw Energy =

$$WthBPCG_{gi} = \left(\left(\int_{min\left(EI_{gi}^{DA},0\right)}^{EI_{gi}^{RT}} C_{gi}^{RT} - LBMP_{gi}^{RT} * \left(EI_{gi}^{RT} - min(EI_{gi}^{DA},0) \right) \right) * \frac{S_i}{3600} \right)$$

$$- \left(NASR_{gi}^{TOT} - NASR_{gi}^{DA} \right) - RRAP_{gi} + RRAC_{gi}$$

where:

$Supplier_g$ = Generator g or Aggregation g;

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

EI_{gi}^{RT} = (i) for any intervals in which there are maximum generation pickups, and the three intervals following, for Suppliers in the location for which the maximum generation pickup has been called -- the average Actual Energy Injections, expressed in MWh, for Generator g in interval i, and for all other Suppliers EI_{gi}^{RT} is as defined in Section 18.4.2 above.

(ii) for any intervals in which there are large event reserve pickups and the three intervals following, EI_{gi}^{RT} is as defined in Section 18.4.2 above.

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

The definition of all other variables is identical to those defined in Section 18.4 above.

In the event that the ISO re-institutes penalties for poor Regulation Service performance under Section 15.3.8 of Rate Schedule 3 such penalties will not be taken into account when calculating supplemental payments under this Attachment C.

18.6 Real-Time BPCG For External Transactions

External Transactions are not eligible to receive Bid Production Cost guarantee payments in the Real-Time Market.

18.7. BPCG for Long Start-Up Time Generators Whose Starts are Aborted by the ISO Prior to their dispatch

18.7.1 Eligibility for BPCG for Long Start-Up Time Generators Whose Starts Are Aborted by the ISO Prior to their Dispatch

A Supplier that bids on behalf of a long start-up time Generator (i.e., a Generator that cannot be scheduled by SCUC to start up in time for the next Dispatch Day) that is committed by the ISO for reliability purposes as a result of a Supplemental Resource Evaluation and whose start is aborted by the ISO prior to its dispatch, as described in Section 4.2.5 of the ISO Services Tariff, shall be eligible to receive a Bid Production Cost guarantee payment under this Section 18.7.

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

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

18.8 BPCG For Special Case Resources

18.8.1 Eligibility for Special Case Resources BPCG

Any Supplier that bids a Special Case Resource that is committed by the ISO for an event in the Real-Time Market shall be eligible to receive a Bid Production Cost guarantee payment under this Section 18.8. Suppliers shall not be eligible for a Special Case Resource Bid Production Cost guarantee payment for the period over which a Special Case Resource is performing a test.

18.8.2 Methodology for Determining Special Case Resources BPCG

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

18.9 Proration Of Start-Up Bid For Generators That Are Committed In The Day-Ahead Market, Or Via Supplemental Resource Evaluation

18.9.1 Eligibility to Recover Operating Costs and Resulting Obligations

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

Generators that receive Day-Ahead or SRE schedules that are not scheduled to operate in real-time, or that do not operate in real-time, at the MW level included in the Minimum Generation Bid for the first hour of the Generator's Day-Ahead or SRE schedule, for the longer of (a) the duration of the Generator's Day-Ahead or SRE schedule, or (b) the minimum run time specified in the Bid that was accepted for the first hour of the Generator's Day-Ahead or SRE schedule, will have the start-up cost component of the Bid Production Cost guarantee calculation prorated in accordance with the formula specified in Section 18.9.2, below. The rules for prorating the start-up cost component of the Bid Production Cost guarantee calculation apply both to operation within the Dispatch Day and to operation on the day following the Dispatch Day to satisfy the minimum run time specified for the hour in which the Generator was scheduled to start-up on the Dispatch Day.

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

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

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

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

$$TotMWReq_{g,s} = MinOpMW_{g,s} * n_{g,s}$$

Where:

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

$MinOpMW_{g,s}$ = Minimum operating level (in MW) specified by Generator g in its hour s Bid

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

$$n_{g,s} = max\left(LastHrDASched_{g,s}, LastMinRunHr_{g,s}\right)$$

Where:

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

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

18.9.2.2 Calculation of Prorated Start-Up Cost

$$ProratedSUC_{g,s} = SubmittedSUC_{g,s} * \frac{\sum_{h=s}^{n_{g,s}} MinOpEnergy_{g,h,s}}{TotalMWReq_{g,s}}$$

Where:

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

$SubmittedSUC_{g,s}$= the Start-Up Bid submitted (as mitigated, where appropriate) for Generator g that is scheduled to start in hour s

$MinOpEnergy_{g,h,s}$ = the amount of Energy produced during hour h by Generator g during the time required to complete both its minimum run time and its Day-Ahead schedule, if that generator is started in hour s. $MinOpEnergy_{g,h,s}$ is calculated as follows:

$$MinOpEnergy_{g,h,s} = min(MetActEnergy_{g,h}, MinOpMW_{g,s})$$

Where:

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

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

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

b. A Generator must be scheduled and operate in real-time to produce Energy consistent with the $MinOpMW_{g,s}$ specified in the accepted Start-Up Bid for each hour that it is expected to run. *See* Section 18.9.2.1, above. These rules do not specify or require any particular bidding construct that must be used to achieve the desired commitment.

However, submitting a self-committed Bid may preclude a Generator from receiving a BPCG. *See, e.g.,* Sections 18.2.1.2.2 and 18.4.1.2.3 of this Attachment C.

19 Attachment D – This Section is reserved for future use

20 Attachment E - Procedures for Reserving and Correcting Erroneous Energy and Ancillary Services Prices

These provisions shall control the reservation and correction of Energy and Ancillary Services prices that are posted on OASIS and used in ISO settlements. The ISO shall review market clearing prices calculated for Energy and Ancillary Services and shall correct any price it determines not to have been calculated in accordance with the ISO tariffs as established in this Attachment E.

20.1 Market Clearing Price Errors Requiring Correction

To be deemed a price that does not require correction, an Energy and Ancillary Service clearing price must be: (i) calculated correctly according to the relevant provision(s) of the ISO tariffs; (ii) based on the appropriate price-setting resource (*i.e.*, the marginal resource, except as otherwise provided by the ISO tariffs); and (iii) posted to the OASIS before the reservation deadline.

20.1.1 Calculation Errors

A calculation error occurs when, notwithstanding the selection of the correct price-setting unit, an Energy or Ancillary Service market clearing price is computed in a manner that is inconsistent with the ISO tariffs. In addition, a calculation error occurs when no price is calculated or a correctly calculated price is not timely posted to OASIS. Subject to the deadlines established in Section 20.3 of this Attachment E, the ISO shall correct a price that it determines to have resulted from a calculation error.

20.1.2 Errors in Selecting the Price-Setting Resource

The ISO shall schedule, commit, and dispatch supply resources on a least total bid production cost basis. An Energy or Ancillary Services market clearing price must be based on the appropriate price-setting resource (*i.e.*, the marginal resource, unless otherwise provided by the tariffs). Subject to the deadlines established in Section 20.3 of this Attachment E, the ISO shall correct a price that it determines to have resulted from an error in selecting the appropriate price-setting resource.

20.2 Methodology for Correcting Prices

The ISO shall recalculate an erroneous price in accordance with the relevant provision(s) of the ISO tariffs. In the event that the ISO cannot practicably recalculate an erroneous price, due to the unavailability of necessary data or otherwise, the ISO shall determine a price as close as reasonably possible to the price that should have resulted from the operation of the relevant tariff provisions consistent with system conditions by drawing as appropriate from: (i) prices calculated for electrically similar points, (ii) prices in surrounding intervals, (iii) Real-Time Commitment prices, (iv) Day-Ahead Market prices, or (v) Real-Time Dispatch prices for the affected interval(s).

In the event of a catastrophic failure of the ISO's price calculation software, the ISO shall provide notice of the problem to the Commission and Customers as soon as possible, but in no event later than the next business day. Within two additional business days, the ISO shall inform the Commission and Customers regarding the nature of the problem and the schedule for determining the procedures to be used by the ISO to construct prices. Following consultation with Transmission Customers regarding the procedures to be used, the ISO shall construct prices as close as possible to the prices that should have resulted from the application of the market rules established in the tariffs to prevailing system conditions.

20.3 Deadlines for Price Corrections

The ISO shall provide notice reserving a potentially erroneous real-time price not later than 17:00 of the calendar day following the operating day for which the price was calculated. The ISO shall provide notice reserving a potentially erroneous Day-Ahead price prior to the start of the operating day for which the price was calculated.

The ISO shall correct a price it has timely reserved and determines to be erroneous and shall provide notice of the correction as soon as possible, but not later than: (i) two business days after the operating day for which the correction applies in the case of a Day-Ahead price; or (ii) four business days after the operating day for which the correction applies in the case of a real-time price. Whenever possible, the ISO will make price corrections prior to the reservation deadline and will provide notice of those corrections along with the reservation notices.

Erroneous prices not reserved and corrected within these timeframes shall not be corrected by the ISO except as directed by the Commission or a court of competent jurisdiction. Nothing herein shall be construed to restrict any stakeholder's right to seek redress from the Commission in accordance with the Federal Power Act.

20.4 Reporting Requirements

In the event that the ISO corrects a price, it shall provide Customers with supporting tariff references and information regarding:

(i) the affected price intervals;

(ii) the affected LBMP zone(s) or the affected Ancillary Service(s);

(iii) the type of pricing error (either a calculation error or an error in selecting the price-setting resource);

(iv) a description of the nature of the pricing error;

(v) a description of the underlying cause of the pricing error; and

(vi) the price correction method used.

The ISO shall provide this information to Transmission Customers as soon as possible but within ten days following the price correction unless extraordinary circumstances necessitate additional time to provide this information, in which case the ISO shall provide this information as soon as possible, but no later than 30 days following the price correction.

The ISO shall provide quarterly reports to Customers regarding the cause of each error requiring correction and steps taken or planned by the ISO to eliminate or diminish the incidence of the error in the future. In its quarterly reports, the ISO shall also detail any price errors of which it becomes aware after the deadlines for reservation or correction of the price error.

20.5 Liability

The ISO shall not be liable for errors of commission or omission relating to price errors that are left uncorrected by operation of these rules except in cases of gross negligence or intentional misconduct.

21 Attachment F - Bid Restrictions

21.1 Definitions

Except as noted below, all capitalized terms used in Attachment F shall have the meanings specified in Article 2 of the ISO Services Tariff, or in Section 1 of the ISO OATT. In addition, the following terms, which are not defined in the ISO Tariffs, shall have the meanings specified below.

"Bid Restriction" shall mean the maximum or minimum Bid Price that may be submitted in connection with certain Bids, as specified in Sections 21.4 and 21.5 of this Attachment F.

"Emergency External Purchases" shall mean the purchase, by the ISO, of Capability or Energy from External Suppliers for the purpose of eliminating an Operating Reserve deficiency, as described in the ISO Procedures.

"Price Cap Load Bid" a Bid identifying the maximum price above which an Internal Load is not willing to be scheduled in the Day-Ahead Market.

21.2 Supremacy of Attachment F

During the period that this Attachment F is in effect, the provisions set forth herein shall be deemed incorporated by reference into every provision of the ISO Services Tariff affected by this Attachment F, including each of the ISO Services Tariff's Rate Schedules and Attachments. In the event of a conflict between the terms of this Attachment F and the terms of any other provision of the ISO Services Tariff, the terms of Attachment F shall prevail. The Bid Restrictions specified in this Attachment F do not interfere with, prevent or supplant the NYISO's authority to apply any of the market power mitigation measures set forth in its Tariffs.

21.3 [This Section is Reserved for Future Use]

21.4 Establishment of Bid Restrictions

The Bid Restrictions for all Bids are specified below. If a Bid Price exceeds an applicable maximum Bid Restriction or is less than an applicable minimum Bid Restriction, the Bid shall either be automatically rejected by the ISO or shall be reduced in accordance with the rules specified in Section 23.7 of the ISO Services Tariff.

21.4.1 Incremental Energy Bids and Minimum Generation Bids

Maximum Day-Ahead and real-time Incremental Energy Bids and Minimum Generation Bids submitted for NYCA Resources are restricted to the higher of (a) $1,000/MWh, or (b) a Resource-specific, verified, cost-based reference level determined in accordance with Section 23.7 of the ISO Services Tariff. Incremental Energy Bids and Minimum Generation Bids submitted for NYCA Resources that exceed the maximum Bid Restriction shall be reduced in accordance with Section 23.7 of the ISO Services Tariff. Bid costs associated with Incremental Energy Bids and Minimum Generation Bids that are reduced, but are later verified, may be eligible for recovery, in whole or in part, in a Bid Production Cost Guarantee payment in accordance with Sections 18 and 23.7 of the ISO Services Tariff.

For purposes of determining commitment and dispatch, and setting market clearing prices, maximum Day-Ahead and real-time Incremental Energy Bids and Minimum Generation Bids submitted for NYCA Resources shall not be permitted to exceed $2,000/MWh. Timely submitted, verified Bid Prices that exceed $2,000/MWh may be eligible for recovery, in whole or in part, in a Bid Production Cost Guarantee payment in accordance with Sections 18 and 23.7 of the ISO Services Tariff.

Minimum Day-Ahead and real-time Incremental Energy Bids and Minimum Generation Bids submitted for NYCA Resources are restricted to a Bid Price of no less than -$1,000/MWh.

Incremental Energy Bids and Minimum Generation Bids submitted for NYCA Resources that violate the minimum Bid Restriction shall be automatically rejected by the ISO.

21.4.2 Bids to Import or to Export Energy

Day-Ahead and real-time Decremental Bids to Import Energy into the NYCA are restricted to a maximum Bid Price of $2,000/MWh. Day-Ahead and real-time Decremental Bids to Import Energy into the NYCA are restricted to a minimum Bid Price of -$1,000/MWh. Decremental Bids to Import Energy into the NYCA that violate the maximum Bid Restriction or the minimum Bid Restriction shall be automatically rejected by the ISO.

Day-Ahead and real-time Sink Price Cap Bids to Export Energy from the NYCA are restricted to a maximum Bid Price of $2,000/MWh. Day-Ahead and real-time Sink Price Cap Bids to Export Energy from the NYCA are restricted to a minimum Bid Price of -$1,000/MWh. Sink Price Cap Bids to Export Energy from the NYCA that violate the maximum Bid Restriction or the minimum Bid Restriction shall be automatically rejected by the ISO.

21.4.3 Bids to Schedule Wheels Through the NYCA

Day-Ahead and real-time Decremental Bids to schedule Wheels Through the NYCA are restricted to a maximum Bid Price of $1,000/MWh and to a minimum Bid Price of -$1,000/MWh. Decremental Bids to schedule Wheels Through the NYCA that violate the maximum Bid Restriction or the minimum Bid Restriction shall be automatically rejected by the ISO.

21.4.4 CTS Interface Bids

Real-time CTS Interface Bids are restricted to a maximum Bid Price of $1,000/MWh and to a minimum Bid Price of -$1,000/MWh. CTS Interface Bids that violate the maximum Bid Restriction or the minimum Bid Restriction shall be automatically rejected by the ISO.

21.4.5 Virtual Load Bids and Virtual Supply Bids

Day-Ahead Virtual Load Bids are restricted to a maximum Bid Price of $2,000/MWh. Day-Ahead Virtual Load Bids are restricted to a minimum Bid Price of -$1,000/MWh. Virtual Load Bids that violate the maximum Bid Restriction or the minimum Bid Restriction shall be automatically rejected by the ISO.

Day-Ahead Virtual Supply Bids are restricted to a maximum Bid Price of $2,000/MWh. Day-Ahead Virtual Supply Bids are restricted to a minimum Bid Price of -$1,000/MWh. Virtual Supply Bids that violate the maximum Bid Restriction or the minimum Bid Restriction shall be automatically rejected by the ISO.

21.4.6 Price Cap Load Bids

Day-Ahead Price Cap Load Bids are restricted to a maximum Bid Price of $2,000/MWh. Day-Ahead Price Cap Load Bids are restricted to a minimum Bid Price of -$1,000/MWh. Price Cap Load Bids that violate the maximum Bid Restriction or the minimum Bid Restriction shall be automatically rejected by the ISO.

21.5 Applicability of Bid Restrictions

21.5.1 The Bid Restriction established in Section 21.4 shall apply to Day-Ahead and real-time Energy Bids, Minimum Generation Bids, Decremental Bids, Price Cap Load Bids, Sink Price Cap Bids and real-time CTS Interface Bids , as applicable. All Suppliers and Demand Side Resources, whether External or Internal to the NYCA, shall be subject to a Bid Restriction for all Bids specified herein.

21.5.2. The Bid Restriction established in Section 21.4 shall not apply to Ancillary Services Bids, Start-Up Bids or to any other Bid that is not specified in Section 21.5.1, provided however a Bid floor of $0.00 shall apply to Regulation Capacity Bids and Regulation Movement Bids. This Attachment F does not supercede the reference level calculation rule or special mitigation procedures applicable to 10-Minute Non-Synchronized Reserve Bids under Sections 23.3.1.4.4 and 23.5.3 of Attachment H to this ISO Services Tariff.

21.5.3 Bid Restrictions shall not apply to Emergency External Purchases. Bids or Offers made in connection with External Emergency Purchases shall not establish market-clearing prices.

22 Attachment G - Emergency Demand Response Program

22.1 Effective Date

The Emergency Demand Response Program became effective on May 1, 2001. The ISO will review the Emergency Demand Response Program's performance semi-annually and will propose appropriate changes as necessary.

22.2 Qualification Requirements For Curtailment Services Providers

Curtailment Services Providers must be Customers or, in the case of entities that would be Customers solely for the purpose of participating in the Emergency Demand Response Program, must be Limited Customers. The requirements for Limited Customers are set forth in ISO Procedures.

Curtailment Service Providers must: (i) comply with the registration requirements set forth in the ISO Procedures; (ii) designate one or more contact persons to receive ISO communications; (iii) comply with the metering requirements set forth below in Section 22.8 of this Attachment, and as provided in ISO Procedures; and (iv) in accordance with ISO Procedures, be capable of reducing at least 100 kW of NYCA Load in a single Load Zone within two hours of receiving notice of the ISO's deployment of the Emergency Demand Response Program. The required Load reduction may be accomplished by Curtailing Load and/or by serving Load with a Local Generator pursuant to ISO Procedures.

22.3 Relationship Of The Emergency Demand Response Program To Other Demand Side Response Measures

The Emergency Demand Response Program is intended to complement other demand-side response programs developed by the ISO, the PSC and LSEs. Except as noted in Section 22.4 below, Curtailment Service Providers are free to participate in other demand response programs, to the extent that those programs allow: provided, however, that the ISO will pay

under only one program for each MWh of delivered Load reduction. This restriction is not intended to limit payment for installed capacity otherwise available to Curtailment Service Providers.

22.4 Prohibition On The Double Subscription Of Load

Curtailment Service Providers may not offer to reduce NYCA Load in the Emergency Demand Response Program that has already been subscribed to the Program by another Curtailment Service Provider.

22.5 ISO Deployment Of The Emergency Demand Response Program

The ISO may deploy the Emergency Demand Response Program in response to: (i) a Real-Time Locational, Zonal or NYCA-wide Operating Reserve shortage or an ISO peak forecast of a locational, zonal or NYCA-wide Operating Reserve shortage; (ii) an ISO-declared Major Emergency State; (iii) a request for assistance from a Transmission Owner for Load reduction purposes or as a result of a Local Reliability Rule; or (iv) in the event that the ISO instructs Special Case Resources to reduce their consumption of Energy.

In accordance with ISO Procedures, the ISO may elect to call on a subset of participants subscribed in the Emergency Demand Response Program within Load Zone J when responding to the request for assistance from the Transmission Owner for Load reductions within the Load Zone.

22.6 Notification To Curtailment Service Providers

The ISO will, whenever possible, provide Curtailment Service Providers with day-ahead notice that it may deploy the Emergency Demand Response Program. Providing day-ahead notice of possible deployment does not commit the ISO to deploy the Emergency Demand Response Program or to make payments. The notice shall specify the time at which the ISO

requests that Load reductions begin and shall, whenever possible, specify when the need for Load reductions will end. The ISO will also provide notice to Curtailment Service Providers of the deployment of the Emergency Demand Response Program at least two hours in advance of the start time specified to begin Load reductions, except that, when necessary, the ISO may immediately deploy the Emergency Demand Response Program without advance notice and call upon Curtailment Service Providers to provide Load reductions as soon as possible.

22.7 Voluntariness Of Emergency Demand Response Program

Participation in the Emergency Demand Response Program shall be voluntary. The ISO shall not penalize Curtailment Service Providers that decline to take steps to reduce Load when the Emergency Demand Response Program is deployed. Special Case Resources that have not sold their capacity shall be temporarily transferred to the Emergency Demand Response Program for each month in which their capacity remains unsold.

22.8 Metering

Curtailment Service Providers shall provide sufficient hourly interval metering data, pursuant to ISO procedures, to allow verification of their Load reduction performance.

22.9 Verification

Curtailment Service Providers shall report their Load reduction performance data to the ISO in accordance with ISO Procedures on or before the 75th day after each deployment of the Emergency Demand Response Program. If the ISO does not receive timely performance data, the ISO shall refuse to pay for that Curtailment Service Provider's claimed Load reductions. All Load reduction data are subject to audit by the ISO. If the ISO determines that it has made an erroneous payment to a Curtailment Service Provider it shall have the right to recover it either by reducing other payments to that Curtailment Service Provider or by any other lawful means.

22.10 Payment

The ISO shall pay Curtailment Service Providers that have caused a verified reduction in Load in response to the deployment of the Emergency Demand Response Program. Payment shall be made in the manner set forth in this section and in accordance with ISO Procedures.

22.10.1 Curtailment Service Provider Eligibility Requirements for Payment

When the ISO deploys an Emergency Demand Response Program event (for the purposes of this subsection, "a deployment event"), each Curtailment Service Provider shall be eligible to be paid for verified Load reductions made during each hour of the payment eligibility period. The first hour of the payment eligibility period shall begin at the top of the hour within which the deployment event is to start as identified by the ISO. For immediate deployment events, the ISO-identified start is the time of the deployment message. The payment eligibility period shall end at the later of the third consecutive hour following the first hour of the payment eligibility period or the deployment event end time identified in the deployment message; provided, however, that the end time may be adjusted by the ISO in messages subsequent to the deployment message.

To be eligible for payment provided under this section the Curtailment Service Provider shall submit to the ISO as provided by Sections 22.8 and 22.9 above and in accordance with ISO Procedures, timely and sufficient Load reduction performance data including, but not limited to, interval metering data for each hour of the payment eligibility period.

22.10.2 Payment for Program Deployment

22.10.2.1 Program deployment lasting two hours or fewer

For deployment events of two hours or less, each Curtailment Service Provider shall be paid the higher of $500/MWh, or the zonal Real-Time LBMP for its verified Load reduction during the first two hours of the payment eligibility period, provided however if the deployment

event starts after the top of the hour, the Curtailment Service Provider that reduces Load shall be paid the higher of $500/ MWh or the zonal Real-Time LBMP for its verified Load reduction during the third hour of the payment eligibility period. Each Curtailment Service Provider shall be paid the zonal Real-Time LBMP for each MWh of its verified Load reduction for the remaining hour(s) of the payment eligibility period.

22.10.2.2. Program deployment lasting between two and three hours

If the ISO deploys the Emergency Demand Response Program for more than two hours but not exceeding three hours, each Curtailment Service Provider that reduces Load shall be paid the higher of $500/MWh or the zonal Real-Time LBMP for its verified Load reduction during the first three hours of the payment eligibility period or for each hour of the payment eligibility period in which the program is deployed as established by the start and end times specified by the ISO in the deployment message(s). Each Curtailment Service Provider shall be paid the zonal Real-Time LBMP for each MWh of its verified Load reduction for the remaining hour of the payment eligibility period, if applicable.

22.10.2.3 Program deployment exceeding three hours

If the ISO deploys an Emergency Demand Response Program event that exceeds three hours, each Curtailment Service Provider that reduces Load shall be paid the higher of $500/MWh or the zonal Real-Time LBMP for its verified Load reduction during each hour of the payment eligibility period.

22.11 Cost Allocation

Payments made to Curtailment Service Providers for Load reductions provided under the Emergency Demand Response Program shall be recovered from all Transmission Customers

pursuant to Rate Schedule 1 of the ISO OATT.

23 Attachment H - ISO Market Power Mitigation Measures

23.1. Purpose and Objectives

23.1.1 These ISO market power mitigation measures ("Mitigation Measures") are intended to provide the means for the ISO to mitigate the market effects of any conduct that would substantially distort competitive outcomes in the ISO Administered Markets, while avoiding unnecessary interference with competitive price signals. Consistent with the provisions of the ISO's Market Monitoring Plan ("Plan") that is set forth in Attachment O to the ISO Services Tariff, these Mitigation Measures are intended to minimize interference with open and competitive markets, and thus to permit, to the maximum extent practicable, price levels to be determined by competitive forces under the prevailing market conditions. To that end, the Mitigation Measures authorize the mitigation only of specific conduct that exceeds well-defined thresholds specified below.

23.1.2 In addition, the ISO and its Market Monitoring Unit shall monitor the markets the ISO administers for conduct that the ISO or the Market Monitoring Unit determines constitutes an abuse of market power but that does not trigger the thresholds specified below for the imposition of mitigation measures by the ISO. If the ISO identifies or is made aware of any such conduct, and in particular conduct exceeding the thresholds for presumptive market effects specified in Section 23.3.2.3 below, it shall make a filing under Section 205 of the Federal Power Act, 16 U.S.C. § 824d (1999) ("§ 205") with the Commission requesting authorization to apply appropriate mitigation measures. Any such filing shall identify the particular conduct the ISO believes warrants mitigation, shall propose a specific mitigation measure for the conduct, shall incorporate or address the

recommendation of its Market Monitoring Unit, and shall set forth the ISO's justification for imposing that mitigation measure. The Market Monitoring Unit's reporting obligations are specified in Sections 30.4.5.3 and 30.4.5.4 of Attachment O. The responsibilities of the Market Monitoring Unit that are addressed in this section of the Mitigation Measures are also addressed in Section 30.4.6.2.1 of Attachment O.

23.2 Conduct Warranting Mitigation

23.2.1 Definitions

The following definitions are applicable to this Attachment H:

For purposes of Section 23.4.5 of this Attachment H, "**Additional CRIS MW**" shall mean the MW of Capacity for which CRIS was requested for an Examined Facility pursuant to the provisions in ISO OATT Sections 25, 30, 32, or 40 (OATT Attachments S, X, Z, or HH), including either: (i) all, or a portion, of the MW of Capacity of that Examined Facility for which CRIS had not been obtained in prior Class Years through a prior Class Year process, in prior Cluster Studies through a prior Cluster Study Process, or through a transfer completed in accordance with OATT Sections 25 or 40 (OATT Attachment S or HH); and/or (ii) all, or a portion, of an increase in the Capacity of that Examined Facility. Additional CRIS MW does not include any MW quantity of CRIS that is exempt from an Offer Floor pursuant to Section 23.4.5.7.7(a) or (b), Section 23.4.5.7.8, or an increase of 2 MW or less in an Examined Facility's MW quantity of CRIS obtained pursuant to Section 30.3.2.6 of Attachment X or Section 40.5.6.6 of Attachment HH to the OATT.

"**Additional SDU Study**" shall mean a deliverability study that an Interconnection Customer may elect to pursue as that term is defined in, as applicable, OATT Section 25 or 40 (OATT Attachment S or HH).

For purposes of Section 23.4.5 of this Attachment H, "**Affiliated Entity**" shall mean, with respect to a person or Entity:

i) all persons or Entities that directly or indirectly control such person or Entity;

ii) all persons or Entities that are directly or indirectly controlled by or under common control with such person or Entity, and (1) are authorized under ISO Procedures to participate in a market for Capacity administered by the ISO, or (2) possess, directly or indirectly, an ownership, voting or equivalent interest of ten percent or more in a Mitigated Capacity Zone Installed Capacity Supplier;

iii) all persons or Entities that provide services to such person or Entity, or for which such person or Entity provides services, if such services relate to the determination or submission of offers for Unforced Capacity in a market administered by the ISO or offers of capacity from a Generator electrically located in a MCZ Import Constrained Locality; or

iv) all persons or Entities, except if for ISP UCAP MW or an RMR Generator, with which such person or Entity has any form of agreement under which such person or Entity has retained or has conferred rights of (i) Control of Unforced Capacity or (ii) the ability to determine the quantity or price of offers to supply capacity from a Generator that has Capacity Resource Interconnection Service, pursuant to the applicable provisions of Attachments S, X, Z, or HH to the ISO OATT and is electrically located in an MCZ Import Constrained Locality, even if such capacity does not meet the requirements to be Unforced Capacity.

In the foregoing definition, "**control**" means the possession, directly or indirectly, of the power to direct the management or policies of a person or Entity, and shall be rebuttably presumed from an ownership, voting or equivalent interest of ten percent or more.

Catastrophic Failure: shall mean a Forced Outage initially suffered by a Generator which would have reasonably required a repair time of at least 270 days, from the date of the event resulting in the Forced Outage, had it, or a comparable Forced Outage been suffered at a generating facility that is reasonably the same as or similar to the Generator's, the owner of which is intending to return it to service. Repair time includes the reasonable number of days for initial clean up, safety inspections, engineering assessment; damage assessment, cost estimates; site prep and clean up, equipment orders, and actual repair, provided the foregoing are necessitated by the Catastrophic Failure. The determination that a Generator has suffered a Catastrophic Failure shall be based on a technical/engineering evaluation, shall be made by the ISO, and may be made at any time following the event that caused the Forced Outage provided that adequate information is provided to the ISO to support such determination.

"**Class Year Study**" means a Class Year Interconnection Facilities Study as that term is defined in OATT Section 25 (OATT Attachment S).

"**Cleared UCAP**" means the amount of MW (rounded down to the nearest tenth of a MW) that had been subject to an Offer Floor but has cleared in accordance with Section 23.4.5.7.

Cluster Baseline Assessment means an assessment conducted by the ISO as defined, as applicable, in OATT Section 25 or 40 (OATT Attachment S or HH). Cluster Baseline Assessment shall include the term "Annual Transmission Baseline Assessment" as that term is defined in Section 25 of the ISO OATT (Attachment S).

"**Cluster Study**" means a Cluster Study as that term is defined in OATT Section 40 (OATT Attachment HH).

"Cluster Study Phase I Start Date" shall mean the Phase 1 Study Start Date as that term defined in Section 40.1 to the ISO OATT.

"**Commenced Construction**" shall mean (a) all of the following site preparation work is completed: ingress and egress routes exist; the site on which the Project will be located is cleared and graded; there is power service to the site; footings are prepared; and foundations have been poured consistent with purchased equipment specifications and project design; or (b) the following financial commitments have been made: (i) (A) an engineering, procurement, and construction contract ("EPC") has been executed by all parties and is effective; or (B) contracts (collectively, "EPC Equivalents") for all of the following have been executed by all parties and is effective: (1) project engineering, (2) procurement of all major equipment, and (3) construction of the Project, and (ii) the cumulative payments made by the Interconnection Customer under the EPC or EPC Equivalents to the counterparties to those respective agreements is equal to at least thirty (30) percent of the total costs of the EPC or EPC Equivalents.

"**Competitive and Non-Discriminatory Hedging Contract**" shall mean a contract to hedge a risk associated with a product offered in the ISO Administered Markets between a Non-

Qualifying Entry Sponsor and the Interconnection Customer, Owner or Operator of an Examined Facility with a term that shall not exceed three years (inclusive of all options to extend and extensions) and that the ISO determines has been executed pursuant to a procurement process that satisfies the requirements enumerated below. Competitive and Non-Discriminatory Hedging Contracts shall not be deemed to be a non-qualifying contractual relationship that would prevent an Examined Facility from obtaining a Competitive Entry Exemption pursuant to 23.4.5.7.9 of Attachment H of this Services Tariff. The ISO shall determine that a contract is a Competitive and Non-Discriminatory Hedging Contract only if it concludes, and the Non-Qualifying Entry Sponsor executes a certification confirming that, the contract was executed through a procurement process that met all of the following requirements: (A) both new and existing resources satisfy the requirements of the procurement; (B) the requirements of the procurement were fully objective and transparent; (C) the contract was awarded based on the lowest cost offers of qualified bidders that responded to the solicitation; (D) the procurement terms did not restrict the type of capacity resources that may participate in, and satisfy the requirements of, the procurement; (E) the procurement terms did not include selection criteria that could otherwise give preference to new resources; and (F) the procurement terms did not use indirect means to discriminate against existing resources, including, but not limited to, by imposing geographic constraints, unit fuel requirements, maximum unit heat-rate requirements or requirements for new construction.

"**Constrained Area**" shall mean: (a) the In-City area, including any areas subject to transmission constraints within the In-City area that give rise to significant locational market power; and (b) any other area in the New York Control Area that has been identified by the ISO as subject to transmission constraints that give rise to significant locational market power, and that has been approved by the Commission for designation as a Constrained Area.

For purposes of Section 23.4.5 of this Attachment H, "**Control**" with respect to Unforced Capacity shall mean the ability to determine the quantity or price of offers to supply Unforced Capacity from a Mitigated Capacity Zone Installed Capacity Supplier submitted into an ICAP Spot Market Auction; but excluding ISP UCAP MW or UCAP from an RMR Generator.

For purposes of Section 23.4.5.6 of this Attachment H, **"CRIS Transfer Confirmation Date"** shall mean the date in which the transferor and transferee confirms the proposed CRIS transfer (e.g., through a CRIS transfer notification form submitted prior to August 1st for same location CRIS transfers for active facilities looking to transfer CRIS rights for the next Capability Year) and is considered by ISO, in consultation with the Market Monitoring Unit, to be a date which will become, essentially and practicably, an irreversible action for the transferor with respect to effectuating the CRIS transfer and for purposes with respect to the ISO's issuance of a final physical withholding determination to the transferor.

For purposes of Section 23.4.5.7 "**CRIS MW**" shall mean the MW of Capacity for which CRIS was assigned to a Generator or UDR project pursuant to ISO OATT Sections 25, 30, 32, or 40 (OATT Attachments S, X, Z, or HH).

"**Electric Facility**" shall mean a Generator, an Aggregation or an electric transmission facility.

For purposes of Section 23.4.5 of this Attachment H, "**Entity**" shall mean a corporation, partnership, limited liability corporation or partnership, firm, joint venture, association, joint-stock company, trust, unincorporated organization or other form of legal or juridical organization or entity.

"**Examined Facility**" shall mean (I) each proposed new Generator and proposed new UDR project, and each existing Generator that has ERIS only and no CRIS, that is a member of the Class Year Study or Cluster Study, Additional SDU Study or Expedited Deliverability Study that requested CRIS , or that requested an evaluation of the transfer of CRIS rights from another location in the Class Year Study or Cluster Study commencing in the calendar year in which the Class Year Study determination is being made (the Capability Periods of expected entry as further described below in this Section, the "Mitigation Study Period"), and (II) each (i) existing Generator that did not have CRIS rights, and (ii) proposed new Generator and proposed new UDR project, provided such Generator under Subsection (i) or (ii) is an expected recipient of transferred CRIS rights at the same location regarding which the ISO has been notified by the transferor or the transferee of a transfer pursuant to, as applicable, Section 25.9.4 of Attachment S or Section 40.18.3 of Attachment HH to the ISO OATT that will be effective on a date within the Mitigation Study Period ("Expected CRIS Transferee"). The term "Examined Facilities" does not include any facility exempt from an Offer Floor pursuant to the provisions of Section 23.4.5.7.7; or any Generator or UDR project that meets the definition of Excluded Facilities below. The term "Generator" includes each Generator that plans to participate in a DER Aggregation. In the case of a Project that is comprised of Co-located Storage Resources or a Project that is a Hybrid Storage Resource, each participating Generator or component facility shall be treated as a separate Examined Facility unless the Developer of the Project certifies that all of the Project's participating Generators or component facilities qualify as an Excluded Facility, as defined in this Services Tariff, and it is determined to meet the criteria provided in that definition.

"Exceptional Circumstances": shall mean one or more unavoidable circumstances, as determined by the ISO, that individually or collectively render as unavailable the data necessary for the ISO to perform an audit and review of a Market Party, pursuant to Section 23.4.5.6.2 of this Services Tariff. Exceptional Circumstances may include, but are not limited to: the inaccessibility of the physical facility; the inaccessibility of necessary documentation or other data; and the unavailability of information regarding the regulatory obligations with which the Market Party will be required to comply in order to return its Generator to service which regulatory obligations are not yet known but which will be made known by the applicable regulatory authority under existing laws and regulations provided that none of the above described circumstances are the result of delay or inaction by the Market Party. The magnitude of the repair cost, alone, shall not be an Exceptional Circumstance.

Excluded Facilities shall mean Resources or UDR project(s) that are qualified to satisfy the goals specified in the New York State Climate Leadership and Community Protection Act, Chapter 106 of the Laws of 2019, as may be amended ("CLCPA") and such Resources and UDR Projects will not be subject to review by the NYISO under the BSM rules or otherwise subject to an Offer Floor. Excluded Facilities shall include but are not limited to Resources comprised exclusively of one or more the following technologies: energy storage, demand response, wind generation, solar generation, geothermal generation, hydroelectric generation (which may also

include generation created by tidal, wave and other ocean activity), and fuel cells that operate without utilizing fossil fuel. Excluded Facilities will also include Resources using additional technology types not explicitly listed above and UDR projects that satisfy the CLCPA goals, if the Developer, Owner or Operator of the Resource or UDR project certifies in accordance with Section 23.4.5.7.5 of this Services Tariff and ISO Procedures that the Resource or UDR Project meets one of the following criteria:(i) the Resource technology type is specifically identified by the CLCPA or is publicly identified by New York State as supporting the goals of the CLCPA; (ii) the Resource or UDR project has a contract with the State of New York to achieve the goals of the CLCPA (such as a Tier 1 or Tier 4 contract with NYSERDA); or (iii) the Resource or UDR project is eligible to receive a contract authorized by New York State that is supporting the goals of the CLCPA (such as a Tier 1 or Tier 4 contract with NYSERDA).

"**Expedited Deliverability Study**" shall mean a deliverability study that an eligible Interconnection Customer may elect to pursue as that term is defined in OATT Section 40 (OATT Attachment HH) that may determine the extent to which an existing or proposed facility satisfies the NYISO Deliverability Interconnection Standard at its requested CRIS level without the need for System Deliverability Upgrades. The schedule and scope of the study is defined in Attachment HH.

"**Final Decision Round**" shall have the meaning specified, as applicable, in Section 25 or 40 (Attachment S or HH) of the ISO's Open Access Transmission Tariff.

For purposes of Section 23.4.5 of this Attachment H, "**Going-Forward Costs**" shall mean: either (a) the costs, including but not limited to mandatory capital expenditures necessary to comply with federal or state environmental, safety or reliability requirements that must be met in order to supply Installed Capacity, net of anticipated energy and ancillary services revenues, as determined by the ISO as specified in Section 23.4.5.3, for each of the following instances, as applicable, of supplying Installed Capacity that could be avoided if an Installed Capacity Supplier otherwise capable of supplying Installed Capacity were either (1) to cease supplying Installed Capacity and Energy for a period of one year or more while retaining the ability to re-enter such markets, or (2) to retire permanently from supplying Installed Capacity and Energy; or (b) the opportunity costs of foregone sales outside of a Mitigated Capacity Zone, net of costs that would have been incurred as a result of the foregone sale if it had taken place.

For purposes of Section 23.4.5 of this Attachment H, "**Indicative Mitigation Net CONE**" shall mean the capacity price calculated by the ISO for informational purposes only if there is not an effective ICAP Demand Curve and the Commission (i) has accepted an ICAP Demand Curve for the Mitigated Capacity Zone that will become effective when the Mitigated Capacity Zone is first effective, in which case, the Indicative Mitigation Net CONE shall be the capacity price on such ICAP Demand Curve for the Mitigated Capacity Zone corresponding to the average amount of excess capacity above the Indicative NCZ Locational Minimum Installed Capacity Requirement, as applicable, expressed as a percentage of that requirement that formed the basis for the ICAP Demand Curve accepted by the Commission; or, (ii) has not accepted an ICAP Demand Curve for the Mitigated Capacity Zone, but the ISO has filed an ICAP Demand Curve for the Mitigated Capacity Zone pursuant to Services Tariff Section 5.14.1.2.2.4.11, in which case the Indicative Mitigation Net CONE shall be the capacity price on such ICAP Demand Curve corresponding to the average amount of excess capacity above the Indicative NCZ

Locational Minimum Installed Capacity Requirement, expressed as a percentage of that requirement, that formed the basis for such ICAP Demand Curve.

"**Initial Decision Round**" shall have the meaning specified in Section 40 (Attachment HH) of the ISO OATT. Initial Decision Round shall include the term Initial Decision Period as that term is defined in Section 25 of the ISO OATT (Attachment S).

"**Interconnection Customer**" shall have the meaning specified in Section 40 (Attachment HH) of the ISO's Open Access Transmission Tariff. Interconnection Customer shall include the term Developer as that term is defined in Section 25 or 30 of the ISO OATT (Attachment S or X).

"**Interconnection Facilities Study Agreement**" shall have the meaning specified in Section 30 (Attachment X) of the ISO's Open Access Transmission Tariff.

"**Market Monitoring Unit**" shall have the same meaning in these Mitigation Measures as it has in Attachment O.

"**Market Party**" shall mean any person or entity that is, or for purposes of the determinations to be made pursuant to Section 23.4.5.7 of this Attachment H proposes or plans a Project that would be, a buyer and/or a seller in; or that makes bids or offers to buy or sell in; or that schedules or seeks to schedule Transactions with the ISO in or affecting any of the ISO Administered Markets including through the submission of bids or offers into any External Control Area, or any combination of the foregoing.

For purposes of Section 23.4.5 of this Attachment H, "**Mitigated UCAP**" shall mean one or more megawatts of Unforced Capacity that are subject to Control by a Market Party that has been identified by the ISO as a Pivotal Supplier.

For purposes of Section 23.4.5 of this Attachment H, "**Mitigation Net CONE**" shall mean the capacity price on the currently effective ICAP Demand Curve for the Mitigated Capacity Zone corresponding to the average amount of excess capacity above the Mitigated Capacity Zone Installed Capacity requirement, expressed as a percentage of that requirement, that formed the basis for the ICAP Demand Curve approved by the Commission.

"**Mitigation Study Period**" shall mean the duration of time extending six consecutive Capability Periods and beginning with the Starting Capability Period associated with a Class Year Study, Cluster Study, Additional SDU Study, and/or Expedited Deliverability Study.

"**NCZ Examined Project**" shall mean any Generator or UDR project that is not an Excluded Facility and that is not exempt pursuant to 23.4.5.7.8 and either (i) is in a Class Year or Cluster Study on the date the Commission accepts the first ICAP Demand Curve to apply to a Mitigated Capacity Zone or (ii) meets the criteria found in (II) of the definition of Examined Facility above. An NCZ Examined Project may be at any phase of development or in operation or an Installed Capacity Supplier.

For purposes of Section 23.4.5 of this Attachment H, "Net Cost of New Entry", or "**Net CONE**" shall mean the localized levelized embedded costs of a peaking unit in a Mitigated Capacity Zone, net of the likely projected annual Energy and Ancillary Services revenues of such unit, as

determined in connection with establishing the Demand Curve for a Mitigated Capacity Zone pursuant to Section 5.14.1.2 of the Services Tariff, or as escalated as specified in Section 23.4.5.7 of Attachment H.

"**New Capacity**" shall mean a new Generator, a substantial addition to the capacity of an existing Generator, or the reactivation of all or a portion of a Generator that has been out of service for five years or more that commences commercial service after the effective date of this definition.

For the purposes of Section 23.4.5 of this Attachment H, **"Non-Qualifying Entry Sponsors"** shall mean a Transmission Owner, Public Power Entity, or any other entity with a Transmission District in the NYCA, or an agency or instrumentality of New York State or a political subdivision thereof.

For purposes of Section 23.4.5 of this Attachment H, "**Offer Floor**" for a Mitigated Capacity Zone Installed Capacity Supplier that is not a Special Case Resource shall mean the lesser of (i) a numerical value equal to 75% of the Mitigation Net CONE translated into a seasonally adjusted monthly UCAP value ("Mitigation Net CONE Offer Floor"), or (ii) the numerical value that is the first year value of the Unit Net CONE determined as specified in Section 23.4.5.7, translated into a seasonally adjusted monthly UCAP value using an appropriate class outage rate, ("Unit Net CONE Offer Floor"). The Offer Floor for Additional CRIS MW shall mean a numerical value determined as specified in Section 23.4.5.7.6.

"**Owner**" shall have the meaning specified in Section 31.1.1 of the ISO's Open Access Transmission Tariff.

"Part A Exemption" shall mean an exemption awarded to an Examined Facility (i) pursuant to the Part A Exemption Test conducted by the ISO prior to the Class Year immediately following Class Year 2021 as described in Section 23.4.5.7.2(a) of the Services Tariff or (ii) pursuant to the Part A Exemption Test described in Section 23.4.5.7.3.1 of the Services Tariff which shall be conducted by the ISO beginning with Class Year immediately following Class Year 2021, and in all subsequent Class Year Studies, Cluster Studies, Additional SDU Studies, and Expedited Deliverability Studies that are commenced after August 1, 2022.

"**Part A Exemption Test**" shall mean (i) for any Class Year Study that was conducted prior to the Class Year immediately following Class Year 2021, the test conducted by the ISO to determine if an Examined Facility would be exempt from an Offer Floor under Section 23.4.5.7.2 (a) of the Services Tariff; or (ii) for the Class Year immediately following Class Year 2021 and any subsequent Class Year Study, Cluster Study, Additional SDU Study, and Expedited Deliverability Study that starts after August 1, 2022, the test conducted by the ISO to determine if an Examined Facility shall be exempt from an Offer Floor in accordance with Section 23.4.5.7.3.1 of the Services Tariff.

"Part A Group 1 Examined Facilities" for the Class Year immediately following Class Year 2021 and any subsequent Class Year Study, Cluster Study, Additional SDU Study, and Expedited Deliverability Study that starts after August 1, 2022 shall mean the set of Examined Facilities being evaluated for the Part A Exemption Test described in Section 23.4.5.7.3.1 using

the Part A Mitigation Study Period Years 1 through 3 as determined by the ISO pursuant to the criteria set forth in Section 23.4.5.7.3.1.3 of the Services Tariff.

"Part A Group 2 Examined Facilities" for the Class Year immediately following Class Year 2021 and any subsequent Class Year Study, Cluster Study, Additional SDU Study, and Expedited Deliverability Study that starts after August 1, 2022 shall mean the set of Examined Facilities being evaluated for the Part A Exemption Test described in Section 23.4.5.7.3.1 using the Part A Mitigation Study Period Years 4 through 6 as determined by the ISO pursuant to the criteria set forth in Section 23.4.5.7.3.1.3 of the Services Tariff.

"**Part A Mitigation Study Period Years 1 through 3**" for the Class Year immediately following Class Year 2021 and any subsequent Class Year Study, Cluster Study, Additional SDU Study, and any Expedited Deliverability Study that starts after August 1, 2022 shall mean the evaluation period applied to Part A Group 1 Examined Facilities which shall be considered concurrently to receive a Part A Exemption in accordance with Section 23.4.5.7.3.1 of the Services Tariff. Such evaluation period shall be composed of the three consecutive Capability Years starting with the first Capability Year that will commence two years from the Cluster Study Phase I Start Date.

"**Part A Mitigation Study Period Years 4 through 6**" for the Class Year immediately following the Class Year 2021 and any subsequent Class Year Study, Cluster Study, Additional SDU Study, and any Expedited Deliverability Study that starts after August 1, 2022 shall mean the evaluation period applied to Part A Group 2 Examined Facilities which shall be considered concurrently to receive a Part A Exemption in accordance with Section 23.4.5.7.3.1 of the Services Tariff. Such evaluation period shall be composed of the three consecutive Capability Years starting with the first Capability Year immediately following the Part A Mitigation Study Period Years 1 through 3.

"**Part B Exemption Test**" shall mean the test conducted by the ISO in accordance with 23.4.5.7.2 (b) and ISO Procedures for an Examined Facility in any Class Year Study, Cluster Study, Additional SDU Study, or Expedited Deliverability Study.

For purposes of Section 23.4.5 of this Attachment H, "**Pivotal Supplier**" shall mean (i) for the New York City Locality, a Market Party that, together with any of its Affiliated Entities, (a) Controls 500 MW or more of Unforced Capacity, and (b) Controls Unforced Capacity some portion of which is necessary to meet the New York City Locality Locational Minimum Installed Capacity Requirement in an ICAP Spot Market Auction; (ii) for the G-J Locality, a Market Party that, together with any of its Affiliated Entities, (a) Controls 650 MW or more of Unforced Capacity; and (b) Controls Unforced Capacity some portion of which is necessary to meet the G-J Locality Locational Minimum Installed Capacity Requirement in an ICAP Spot Market Auction; and (iii) for each Mitigated Capacity Zone except the New York City Locality and the G-J Locality, if any, a Market Party that Controls at least the quantity of MW of Unforced Capacity specified for the Mitigated Capacity Zone and accepted by the Commission. Unforced Capacity that are MW of an External Sale of Capacity shall not be included in the foregoing calculations.

"**Project Cost Allocation**" shall have the meaning specified, as applicable, in Section 25 or 40 (Attachment S or HH) of the ISO's Open Access Transmission Tariff.

"**Public Policy Resource**" shall mean for purposes of Section 23.4.5 of this Attachment H, an Examined Facility that is determined by the ISO to be a zero-emitting resource and that does not meet the definition of Excluded Facility under Section 23.2 of this Attachment H and, where applicable, as also determined by the NYISO under Section 23.4.5.7.5.1 of this Attachment H. A resource may request an ex-ante determination from the ISO if it qualifies as a zero-emitting resource prior to their entrance into a Class Year Study, Cluster Study, or Expedited Deliverability Study. The ISO, in consultation with the MMU, shall issue a determination no later than 20 days after the necessary information has been submitted for consideration. This determination will be binding as long as the resource's technology and characteristics are not modified before issuance of a final determination to the Examined Facility. The ISO will post such ex-ante determinations to its website concurrent with the response to the resource. Public Policy Resources shall be identified and posted on the ISO website no later than the ISO's posting of the Part A Group 1 Examined Facilities and the Part A Group 2 Examined Facilities for the Class Year immediately following Class Year 2021, and any subsequent Class Year Study, Cluster Study, Additional SDU Study, and Expedited Deliverability Study that start after August 1, 2022, as provided in Section 23.4.5.7.3.1.4 of this Services Tariff.

"**Project**" shall have the meaning specified in, as applicable Section 30.1 or 40.1 of the ISO's Open Access Transmission Tariff.

For purposes of Section 23.4.5 of this Attachment H, "**Responsible Market Party**" shall mean the Market Party that is authorized, in accordance with ISO Procedures, to submit offers in an ICAP Spot Market Auction to sell Unforced Capacity from a specified Installed Capacity Supplier.

"**Revised Project Cost Allocation**" shall have the meaning specified in, as applicable, Section 25 or 40 (Attachment S or HH) of the ISO's Open Access Transmission Tariff.

"Self Supply LSE" shall mean a Load Serving Entity in one or more Mitigated Capacity Zones that operates under a long-standing business model to meet more than fifty percent of its Load obligations through its own generation and that is (i) a municipally owned electric system that was created by an act of one or more local governments pursuant to the laws of the State of New York to own or control distribution facilities and/or provide electric service, (ii) a cooperatively owned electric system that was created by an act of one or more local governments pursuant to the laws of State of New York or otherwise created pursuant to the Rural Electric Cooperative Law of New York to own or control distribution facilities and/or provide electric service, (iii) a "Single Customer Entity," or (iv) a "Vertically Integrated Utility." A Self Supply LSE cannot be an entity that is a public authority or corporate municipal instrumentality created by the State of New York (including a subsidiary of such an authority or instrumentality) that owns or operates generation or transmission and that is authorized to produce, transmit or distribute electricity for the benefit of the public unless it meets the criteria provided in section (i), (ii), or (iii) of this definition. For purposes of this definition only: "Vertically Integrated Utility" means a utility that owns generation, includes such generation in a non-bypassable charge in its regulated rates, earns a regulated return on its investment in such generation, and that as of the date of its request

for a Self Supply Exemption, has not divested more than seventy-five percent of its generation assets owned on May 20, 1996; and "Single Customer Entity" means an LSE that serves at retail only customers that are under common control with such LSE, where such control means holding 51% or more of the voting securities or voting interests of the LSE and all its retail customers.

"Starting Capability Period" is the Summer Capability Period that will commence three years from the Cluster Study Phase I Start Date and shall be the start of the Mitigation Study Period for any Examined Facility in a Cluster Study, as well as any Additional SDU Studies and Expedited Deliverability Studies that are completed while the Cluster Study is ongoing. If no Cluster Study is ongoing when an Expedited Deliverability Study or Additional SDU Study arrives at the Decision Period, the Starting Capability Period used for the purposes of Section 23.4.5 of this Attachment H shall be the Starting Capability Period that applied to the most recently completed Cluster Study.

"**Subsequent Decision Round**" shall have the meaning specified in Section 40 (Attachment HH) of the ISO OATT. Subsequent Decision Round shall include the term Subsequent Decision Period as that term is defined in Section 25 of the ISO OATT (Attachment S).

For purposes of Section 23.4.5 of this Attachment H, "**Surplus Capacity**" shall mean the amount of Installed Capacity, in MW, available in a Mitigated Capacity Zone in excess of the Locational Minimum Installed Capacity Requirement for such Mitigated Capacity Zone.

"**Total Evaluated CRIS MW**" shall mean the Additional CRIS MW requested plus either (i) if the Installed Capacity Supplier previously received an exemption under Sections 23.4.5.7.2(b), 23.4.5.7.6(b), 23.4.5.7.7 or 23.4.5.7.8, all prior Additional CRIS MW since the facility was last exempted under Sections 23.4.5.7.2(b), 23.4.5.7.6(b), or 23.4.5.7.8, or (ii) for all other Installed Capacity Suppliers, all MW of Capacity for which an Examined Facility obtained CRIS pursuant to the provisions in ISO OATT Sections 25, 30, 32, or 40 (OATT Attachments S, X, Z, or HH).

For purposes of Section 23.4.5 of this Attachment H, "**UCAP Offer Reference Level**" shall mean a dollar value equal to the projected clearing price for each ICAP Spot Market Auction determined by the ISO on the basis of the applicable ICAP Demand Curve and the total quantity of Unforced Capacity from all Installed Capacity Suppliers in a Mitigated Capacity Zone for the period covered by the applicable ICAP Spot Market Auction.

For purposes of Section 23.4.5 of this Attachment H, "**Unit Net CONE**" shall mean localized levelized embedded costs of a specified Installed Capacity Supplier, including interconnection costs, and for an Installed Capacity Supplier located outside a Mitigated Capacity Zone including embedded costs of transmission service, in either case net of likely projected annual Energy and Ancillary Services revenues, and revenues associated with other energy products (such as energy services and renewable energy credits, as determined by the ISO, translated into a seasonally adjusted monthly UCAP value using an appropriate class outage rate. The Unit Net CONE of an Installed Capacity Supplier that has functions beyond the generation or transmission of power shall include only the embedded costs allocated to the production and transmission of power, and shall not net the revenues from functions other than the generation or transmission of power.

23.2.2 Conduct Subject to Mitigation

Mitigation Measures may be applied: (i) to the bidding, scheduling or operation of an "Electric Facility"; or (ii) as specified in Section 23.2.4.2.

23.2.3 Conditions for the Imposition of Mitigation Measures

23.2.3.1 To achieve the foregoing purpose and objectives, Mitigation Measures should only be imposed to remedy conduct that would substantially distort or impair the competitiveness of any of the ISO Administered Markets. Accordingly, the ISO shall seek to impose Mitigation Measures only to remedy conduct that:

23.2.3.1.1 is significantly inconsistent with competitive conduct; and

23.2.3.1.2 would result in a material change in one or more prices in an ISO Administered Market or production cost guarantee payments ("guarantee payments") to a Market Party.

23.2.3.2 In general, the ISO shall consider a Market Party's or its Affiliates' conduct to be inconsistent with competitive conduct if the conduct would not be in the economic interest of the Market Party or its Affiliates in the absence of market power. The categories of conduct that are inconsistent with competitive conduct include, but may not be limited to, the three categories of conduct specified in Section 23.2.4 below.

23.2.4 Categories of Conduct that May Warrant Mitigation

23.2.4.1 The following categories of conduct, whether by a single firm or by multiple firms acting in concert, may cause a material effect on prices or guarantee payments in an ISO Administered Market if exercised from a position of market power. Accordingly, the ISO shall monitor the ISO Administered Markets for the following categories of conduct, and shall impose appropriate Mitigation Measures if such conduct is detected and the other applicable conditions for the imposition of Mitigation Measures are met:

23.2.4.1.1 Physical withholding of an Electric Facility, that is, not offering to sell or schedule the output of or services provided by an Electric Facility capable of serving an ISO Administered Market. Such withholding may include, but not be limited to, (i) falsely declaring that an Electric Facility has been forced out of service or otherwise become unavailable, (ii) refusing to offer Bids or schedules for an Electric Facility when such conduct would not be in the economic interest of the Market Party or its Affiliates in the absence of market power (includes refusing to offer Bids or schedules to withdraw Energy for a Generator that must withdraw Energy in order to be able to later inject Energy); (iii); making an unjustifiable change to one or more operating parameters of an Electric Facility or an Aggregation that reduces a Resource's ability to provide Energy or Ancillary Services or (iv) operating a Generator or an Aggregation in real-time at a lower output level than the Generator or Aggregation would have been expected to provide had the Generator or Aggregation followed the ISO's dispatch instructions, in a manner that is not attributable to the Generator's or

Aggregation's verifiable physical operating capabilities and that would not be in the economic interest of the Market Party or its Affiliates in the absence of market power.

For purposes of this Section and Section 23.4.3.2, the term "unjustifiable change" shall mean a change in an Electric Facility's operating parameters that is: (a) not attributable to an Electric Facility's verifiable physical operating capabilities, and (b) is not a rational competitive response to economic factors other than market power.

23.2.4.1.2 Economic withholding of an Electric Facility, that is, submitting Bids for an Electric Facility that are unjustifiably high so that (i) the Electric Facility is not or will not be dispatched or scheduled, or (ii) the Bids will set a market clearing price; or submitting Bids for a Withdrawal-Eligible Generator to withdraw Energy that are unjustifiably high, so that (i) the Electric Facility is or will be dispatched or scheduled to withdraw Energy, or (ii) the Bids will set a market clearing price.

23.2.4.1.3 Uneconomic production from an Electric Facility is increasing the output of an Electric Facility to levels that would not be in the economic interest of the Market Party or its Affiliates in the absence of market power. Uneconomic withdrawal by an Electric Facility is withdrawing Energy that would not be in the economic interest of the Market Party or its Affiliates in the absence of market power.

23.2.4.2 Mitigation Measures may also be imposed, subject to FERC's approval, to mitigate the market effects of a rule, standard, procedure or design feature of an ISO Administered Market that allows a Market Party or its Affiliate to manipulate

market prices or otherwise impair the efficient operation of that market, pending the revision of such rule, standard, procedure or design feature to preclude such manipulation of prices or impairment of efficiency.

23.2.4.3 Taking advantage of opportunities to sell at a higher price or buy at a lower price in a market other than an ISO Administered Market shall not be deemed a form of withholding or otherwise inconsistent with competitive conduct.

23.2.4.4 The ISO and the Market Monitoring Unit shall monitor the ISO Administered Markets for other categories of conduct, whether by a single firm or by multiple firms acting in concert, that have material effects on prices or guarantee payments in an ISO Administered Market. The ISO shall: (i) seek to amend the foregoing list as may be appropriate, in accordance with the procedures and requirements for amending the Plan, to include any such conduct that would substantially distort or impair the competitiveness of any of the ISO Administered Markets; and (ii) seek such other authorization to mitigate the effects of such conduct from the FERC as may be appropriate. The responsibilities of the Market Monitoring Unit that are addressed in this section of the Mitigation Measures are also addressed in Section 30.4.6.2.2 of Attachment O.

23.2.4.5 Merchant Transmission Facilities ("MTF") — the ISO shall monitor Electric Facilities that are MTF subject to the ISO's operational control for the following categories of conduct: (i) physical or economic withholding of the opportunity to schedule transmission service over the MTF, where such withholding may have a material effect on prices or guarantee payments in the

ISO Administered Markets; and (ii) under-delivery of scheduled Energy in Real Time, where such under-delivery may have a material effect on prices or guarantee payments in the ISO Administered Markets. If the ISO identifies conduct that violates either of the standards specified in this Section 23.2.4.5, and that the ISO determines is inconsistent with competitive behavior, it shall inform its Market Monitoring Unit of the behavior it identified for possible referral to FERC's Office of Enforcement.

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.

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.

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:

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

where:

Average Price = the average price in the Real-Time Market in the Constrained Area over the past 12 months, adjusted for fuel price changes, and adjusted for Out-of-Merit Generation dispatch as feasible and appropriate; and

Constrained Hours = the total number of minutes over the prior 12 months, converted to hours (retaining fractions of hours), in which the real-time Shadow Price has been greater than $0.04/MWh, indicating an active constraint, on any interface or facility leading into the Constrained Area in which the Generator is located. For the In-City area, "Constrained Hours" shall also include the number of minutes that a Storm Watch is in effect. Determination of the number of Constrained Hours shall be subject to adjustment by the ISO to account for significant changes in system conditions.

23.3.1.2.2.2 For so long as the In-City area is a Constrained Area, the thresholds specified in subsection 23.3.1.2.2.1 shall also apply: (a) in intervals in which the transmission capacity serving the In-City area is subject to Storm Watch limitations; (b) to an In-City Generator 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 < (Applicable Reference Level – max($25, 80%×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:

$$(heat\ rate * fuel\ costs) + (emissions\ rate * emissions\ allowance\ price) + (other\ variable\ operating\ and\ maintenance\ costs) + opportunity\ costs$$

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 ISOs 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.

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.

23.4.3.3.2 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.

23.4.3.3.3.1.2 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) =

Multiplier × max [Σ_g ▲ BPCG payment$_g$ +

$\Sigma_h \Sigma_g$ (Market Party MWh$_{gh}$ × ▲ LBMP@PTID$_{gh}$) +

max (Σ_h TCC Revenue Calc for Market Party$_h$, 0), 0]

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: (zonal $LBMP_{real\ time}$ - zonal $LBMP_{day\ ahead}$). 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 it 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.

23.4.5 Installed Capacity Market Mitigation Measures

23.4.5.1 If and to the extent that sufficient installed capacity is not under a contractual obligation to be available to serve load in New York and if physical or economic withholding of installed capacity would be likely to result in a material change in the price for installed capacity in all or some portion of New York, the ISO, in consideration of the comments of the Market Parties and other interested parties, shall amend this Attachment H, in accordance with the procedures and requirements for amending the Plan, to implement appropriate mitigation measures for installed capacity markets.

23.4.5.2 Offers to sell Mitigated UCAP in an ICAP Spot Market Auction shall not be higher than the higher of (a) the UCAP Offer Reference Level for the applicable ICAP Spot Market Auction, or (b) the Going-Forward Costs of the Installed Capacity Supplier supplying the Mitigated UCAP. Where an Installed Capacity Supplier is a Pivotal Supplier in some, but not all, Mitigated Capacity Zones in which it has Resources, such Installed Capacity Supplier's offer to sell Mitigated UCAP in any ICAP Spot Market Auction for any Resource for which it is a Pivotal Supplier shall not be higher than the higher of (a) the lowest of the UCAP Offer Reference Levels for each Mitigated Capacity Zone in which such Installed Capacity Supplier has Resources; or (b) if an Offer for a Resource has an applicable Going-Forward Cost, such Going-Forward Cost.

23.4.5.3 An Installed Capacity Supplier's (except for a Distributed Energy Resource and DER Aggregations) Going-Forward Costs for an ICAP Spot Market Auction shall be determined upon the request of the Responsible Market Party for that Installed Capacity Supplier. The Going-Forward Costs shall be determined by the ISO after consultation with the Responsible Market Party, provided such consultation is requested by the Responsible Market Party not later than 50 business days prior to the deadline for offers to sell Unforced Capacity in such auction, and provided such request is supported by a submission showing the Installed Capacity Supplier's relevant costs in accordance with specifications provided by the ISO. Such submission shall show (1) the nature, amount and determination of any claimed Going-Forward Cost, and (2) that the cost would be avoided if the Installed Capacity Supplier is taken out of service or retired, as applicable. If the foregoing requirements are met, the ISO shall determine the level of the Installed Capacity Supplier's Going-Forward Costs and shall seasonally adjust such costs not later than 7 days prior to the deadline for submitting offers to sell Unforced Capacity in such auction. A Responsible Market Party shall request an updated determination of an Installed Capacity Supplier's Going-Forward Costs not less often than annually, in the absence of which request the Installed Capacity Supplier's offer cap shall revert to the UCAP Offer Reference Level. An updated determination of Going-Forward Costs may be undertaken by the ISO at any time on its own initiative after consulting with the Responsible Market Party. Any redetermination of an Installed Capacity Supplier's Going-Forward Costs shall conform to the consultation and

determination schedule specified in this paragraph. The costs that an Installed Capacity Supplier would avoid as a result of retiring should only be included in its Going-Forward Costs if the owner or operator of that Installed Capacity Supplier actually plans to mothball or retire it if the Installed Capacity revenues it receives are not sufficient to cover those costs.

23.4.5.4 Mitigated UCAP shall be offered in each ICAP Spot Market Auction in accordance with Section 5.14.1.1 of the ISO Services Tariff and applicable ISO procedures, unless (a) it has been exported to an External Control Area or sold to meet Installed Capacity requirements outside the Mitigated Capacity Zone in which the ICAP Supplier is a Pivotal Supplier is located in a transaction that does not constitute physical withholding under the standards specified below, or (b) it is Net Unforced Capacity of a Behind-the-Meter Net Generation Resource that is sold to its Host Load in a transaction that does not constitute physical withholding under the standards specified in Section 23.4.5.4.1(b).

23.4.5.4.1 (a) An export to an External Control Area or sale to meet an Installed Capacity requirement outside the Mitigated Capacity Zone in which the ICAP Supplier or Generator with CRIS MW is electrically located (either of the foregoing being referred to as "External Sale of Capacity") may be subject to audit and review by the ISO to assess whether such action constituted physical withholding of UCAP from a Mitigated Capacity Zone. "External Sale UCAP" shall mean the UCAP equivalent of the External Sale of Capacity if known, or otherwise the reasonably projected UCAP equivalent as determined by the ISO. External Sale UCAP shall be deemed to have been physically withheld on the basis of a comparison between the net revenues from UCAP sales that would have been earned by the sale of the External Sale UCAP in a Mitigated Capacity Zone and the net revenues earned from the External Sale of Capacity. The comparison shall be made for the period for which capacity is committed (the "Comparison Period") in each of the shortest term organized capacity markets (the "External

Reconfiguration Markets") for the area and during the period in which the External Sale of Capacity occurred. External Sale UCAP shall be deemed to have been withheld from a Mitigated Capacity Zone if: (1) the Responsible Market Party for the External Sale UCAP could have made all or a portion of the External Sale UCAP available to be offered in the Mitigated Capacity Zone by buying out of its external capacity obligation through participation in an External Reconfiguration Market and timely meeting the requirements to be qualified as an Installed Capacity Supplier; (2) the net revenues over the Comparison Period from sale in the Mitigated Capacity Zone of the External Sale UCAP that could have been made available for sale in that Locality would have been greater by 15% or more, provided that the net revenues were at least $2.00/kilowatt-month more than the net UCAP revenues from that portion of the External Sale UCAP over the Comparison Period; and (3) the Responsible Market Party for the External Sale UCAP is a Pivotal Supplier, or would otherwise have been deemed a Pivotal Supplier if the External Sale UCAP had been available to be offered in the Mitigated Capacity Zone for the Comparison Period.

(b) Any Mitigated UCAP that is Net Unforced Capacity of a Behind-the-Meter Net Generation Resource that is not offered into the ICAP Spot Market Auction in accordance with Section 23.4.5.2 may be subject to audit and review by the ISO, and shall be deemed to have been physically withheld unless (i) the Responsible Market Party has obtained a determination from the ISO pursuant to Section 23.4.5.4.3(b) that the sale to its Host Load would not constitute physical

withholding, and (ii) the Mitigated UCAP that was the subject of the determination pursuant to Section 23.4.5.4.3(b) is actually sold to its Host Load.

23.4.5.4.2 If Mitigated UCAP or External Sale UCAP is not offered or sold as specified above, the Responsible Market Party for such Installed Capacity Supplier or Generator electrically located in a MCZ Import Constrained Locality shall pay the ISO an amount equal to the product of (A) 1.5 times the difference between the Market-Clearing Price for the Mitigated Capacity Zone in the ICAP Spot Market Auction with and without the inclusion of the Mitigated UCAP or External Sale UCAP and (B) the total of (1) the amount of Mitigated UCAP or External Sale UCAP not offered or sold as specified above, and (2) all other megawatts of Unforced Capacity in the Mitigated Capacity Zone under common Control with such Mitigated UCAP or External Sale UCAP. If the failure to offer was associated with the same period as an External Sale of Capacity, and the failure caused or contributed to an increase in UCAP prices in the Mitigated Capacity Zone of 15 percent or more, provided such increase is at least $2.00/kilowatt-month, the Responsible Market Party for such Generator or UDR project electrically located in a MCZ Import Constrained Locality shall be required to pay to the ISO an amount equal to 1.5 times the difference between the average Market-Clearing Price for the Mitigated Capacity Zone in the ICAP Spot Market Auctions for the relevant Comparison Period with and without the External Sale of Capacity in those auctions, times the total of (1) the amount of External Sale UCAP not offered or sold as specified above, and (2) all other megawatts of Unforced Capacity in the Mitigated Capacity Zone under common

Control with such External Sale UCAP. The ISO will distribute any amounts recovered in accordance with the foregoing provisions among the LSEs serving Loads in regions affected by the withholding in accordance with ISO Procedures.

If the NYISO determines that the holder of an External UDR or EDR is required to pay the ISO for (1) the failure to offer the UCAP associated with an External UDR or EDR that has not been returned to the NYCA in any ICAP Spot Market Auction during the subject Capability Period as described in Section 5.12.12.4 of this Services Tariff as well as (2) the failure to offer or sell Mitigated UCAP or External Sale UCAP in accordance with this section of the Services Tariff, then the holder of the applicable External UDR or EDR shall pay the ISO the larger of these two sanction amounts.

23.4.5.4.3 (a) Reasonably in advance of the deadline for submitting offers in an External Reconfiguration Market the Responsible Market Party for External Sale UCAP may request the ISO to provide a projection of ICAP Spot Auction clearing prices for the Mitigated Capacity Zone over the Comparison Period for the External Reconfiguration Market. Such requests, and the ISO's response, shall be made in accordance with the deadlines specified in ISO Procedures. Prior to completing its projection of ICAP Spot Auction clearing prices for the Mitigated Capacity Zone over the Comparison Period for the External Reconfiguration Market, the ISO shall consult with the Market Monitoring Unit regarding such price projection. The Responsible Market Party shall be exempt from a physical withholding penalty as specified in Section 23.4.5.4.2, below, if at the time of the deadline for submitting offers in an External Reconfiguration

Market its offers, if accepted, would reasonably be expected to produce net revenues from the External Sale of Capacity that exceed the net revenues that would have been realized from sale of the External Sale UCAP in the Mitigated Capacity Zone at the ICAP Spot Auction prices projected by the ISO. The responsibilities of the Market Monitoring Unit that are addressed in this section of the Mitigation Measures are also addressed in Section 30.4.6.2.8(a) of Attachment O to this Services Tariff.

(b) At least fifteen business days in advance of the opening of the ICAP Spot Market Auction, a Behind-the-Meter Net Generation Resource can request that the ISO make a determination that the sale of Net Unforced Capacity in a Mitigated Capacity Zone to its Host Load does not constitute physical withholding. The Responsible Market Party shall be exempt from a physical withholding penalty as specified in Section 23.4.5.4.2 if the ISO determines that the Behind-the-Meter Net Generation Resource has demonstrated that the Host Load's actual consumption is planned to exceed its Adjusted Host Load, and it has a documented transaction to provide Net Unforced Capacity to its Host Load. Prior to reaching its decision on a request by a Behind-the-Meter Net Generation Resource that its sale of Net Unforced Capacity to its Host Load would not constitute physical withholding, the ISO shall provide its preliminary determination to the Market Monitoring Unit for review and comment. The responsibilities of the Market Monitoring Unit that are addressed in this section of the Mitigation Measures are also addressed in Section 30.4.6.2.8(b) of Attachment O to this Services Tariff.

23.4.5.5 Control of Unforced Capacity shall be rebuttably presumed from (i) ownership of an Installed Capacity Supplier, or (ii) status as the Responsible Market Party for an Installed Capacity Supplier, but may also be determined on the basis of other evidence. For purposes of determining if a Responsible Market Party is a Pivotal Supplier in a Mitigated Capacity Zone, the presumption of Control of Unforced Capacity can be rebutted by demonstrating to the reasonable satisfaction of the ISO that the ability to determine the price and quantity of offers to supply Unforced Capacity has been conveyed to a person or entity that is not an Affiliated Entity without limitation or condition, but cannot be rebutted by the sale of Unforced Capacity in a Capability Period or Monthly Auction. For any Mitigated Capacity Zone, if the presumption has not been rebutted, and if two or more Market Parties each have rights or obligations with respect to Unforced Capacity from an Installed Capacity Supplier that could reasonably be anticipated to affect the quantity or price of Unforced Capacity transactions in an ICAP Spot Market Auction, the ISO may attribute Control of the affected MW of Unforced Capacity from the Installed Capacity Supplier to each such Market Party. Prior to reaching its decision regarding whether the presumption of control of Unforced Capacity has been rebutted, the ISO shall provide its preliminary determination to the Market Monitoring Unit for review and comment. The responsibilities of the Market Monitoring Unit that are addressed in this section of the Mitigation Measures are also addressed in Section 30.4.6.2.9 of Attachment O to this Services Tariff.

23.4.5.6 Audit, Review, and Penalties for Physical Withholding to Increase Market-Clearing Prices; Alignment with both Short-Term Reliability and Transfer of Deliverability Rights Processes

23.4.5.6.1 Audit and Review of Proposals or Decisions to Remove or Derate Installed Capacity from a Mitigated Capacity Zone

Any proposal or decision by a Market Participant to retire or otherwise remove an Installed Capacity Supplier (except as specified in 23.4.5.6.1.1) from a Mitigated Capacity Zone Unforced Capacity market, or to de-rate the amount of Installed Capacity available from such supplier, may be subject to audit and review by the ISO if the ISO determines that such action could reasonably be expected to affect Market-Clearing Prices in one or more ICAP Spot Market Auctions for a Mitigated Capacity Zone in which the Resource(s) that is the subject of the proposal or decision is located, subsequent to such action; provided, however, no audit and review shall be necessary if the Installed Capacity Supplier is a Generator that is being retired or removed from a Mitigated Capacity Zone as the result of a Forced Outage that began on or after May 1, 2015 that was determined by the ISO to be a Catastrophic Failure.

The ISO's audit or review of any proposal or decision by a Market Participant to retire or otherwise remove an Installed Capacity Supplier from a Mitigated Capacity Zone Unforced Capacity market, or to de-rate the amount of Installed Capacity available from such supplier, (including a review the ISO conducts at the request of a Market Participant before it submits a proposal or makes a decision or a review the NYISO conducts in conjunction with the Short-Term Reliability Process) will consider the rationale offered by the Market Participant to support its proposal or decision. Such an audit or review shall assess whether the Market Participant's proposal or decision has a legitimate economic justification, which may include the economics of complying with regulatory requirements, or is based on an effort to withhold Installed Capacity

physically in order to affect prices. The ISO's audit or review is conducted based on the expectation that a Market Participant's decision to retire or otherwise remove an Installed Capacity Supplier from a Mitigated Capacity Zone, or to de-rate the amount of Installed Capacity available from such supplier, accounts for the information available to that Market Participant at (or before) the time its decision is made on the "decision date" (see, e.g., Sections 23.4.5.6.4.2.1 and 23.4.5.6.4.2.2.1 below) specified by the Market Participant or the CRIS Transfer Confirmation Date for CRIS Transfers described below in Section 23.4.5.6.5. A Market Participant may offer publicly available information and other information available to the Market Participant to support its proposal or decision.

The ISO shall provide the preliminary results of its audit or review to the Market Monitoring Unit for its review and comment. The responsibilities of the Market Monitoring Unit that are addressed in this section of the Mitigation Measures are also addressed in Section 30.4.6.2.10 of Attachment O to this Services Tariff.

23.4.5.6.1.1 A proposal or decision to retire or otherwise remove a (a) Demand Side Resource except one that is (i) a Generator that is electrically located in the NYCA or (ii) a facility, electrically located in the NYCA, comprising two or more resource types one of which is a Generator, behind a single point of interconnection with an Injection Limit of less than 20 MW, and in the case of (i) and (ii) that at any time participated directly in any ISO Administered Market or (b) a DER Aggregation from the Installed Capacity market will not be subject to audit and review. Notwithstanding the foregoing, members of a DER Aggregation otherwise subject to audit or review are not excluded by the preceding sentence.

23.4.5.6.2 Audit and Review of the Reclassification of a Generator in a Mitigated Capacity Zone From a Forced Outage to an ICAP Ineligible Forced Outage

This Section 23.4.5.6.2 shall apply to a Market Participant whose Installed Capacity Supplier is a Generator that began a Forced Outage on or after May 1, 2015.

23.4.5.6.2.1 Any reclassification of an Installed Capacity Supplier that is a Generator in a Mitigated Capacity Zone from a Forced Outage to an ICAP Ineligible Forced Outage by a Market Participant or otherwise, pursuant to the terms of Section 5.18.2.1 of this Services Tariff, may be subject to audit and review by the ISO if the ISO determines that such reclassification could reasonably be expected to affect the Market-Clearing Price in one or more ICAP Spot Market Auctions for a Mitigated Capacity Zone in which the Generator(s) that is the subject of the reclassification is located, subsequent to such action; provided, however, if the Market Participant's Generator experienced the Forced Outage as a result of a Catastrophic Failure, the reclassification of a Generator in a Mitigated Capacity Zone from a Forced Outage to an ICAP Ineligible Forced Outage shall not be subject to audit and review pursuant to this Section 23.4.5.6.2.

The audit and review pursuant to the above paragraph shall assess whether the reclassification of the Generator in a Mitigated Capacity Zone from a Forced Outage to an ICAP Ineligible Forced Outage had a legitimate economic justification or is based on an effort to withhold Installed Capacity physically in order to affect prices. A Market Participant may offer publicly available information and other information available to the Market Participant to justify the reclassification.

The ISO shall provide the preliminary results of its audit or review to the Market Monitoring Unit for its review and comment. The responsibilities of the

Market Monitoring Unit that are addressed in this section of the Mitigation Measures are also addressed in Section 30.4.6.2.10 of Attachment O to this Services Tariff.

23.4.5.6.2.2 The audit and review pursuant to Section 23.4.5.6.2.1 shall be deferred by the ISO beyond the time period established in ISO Procedures for the audit and review of a reclassification of a Generator from a Forced Outage to an ICAP Ineligible Forced Outage if the Generator was in a Forced Outage for at least 180 days before the reclassification and one or more Exceptional Circumstances delayed the acquisition of data necessary for the ISO's audit and review.

The ISO shall conduct the audit and review after its receipt of data that it determines is necessary for the audit and review; provided, however, if, at the time the ISO acquires the necessary data, the Market Participant has Commenced Repair of the Generator, or the Generator is determined by the ISO to have had a Catastrophic Failure, the Market Participant shall not be subject to an audit and review pursuant to Section 23.4.5.6.2.1 of this Services Tariff. A Generator that Commenced Repair while in an ICAP Ineligible Forced Outage but that ceased or unreasonably delayed that repair shall be subject to audit and review by the ISO pursuant to Section 23.4.5.6.2.1 of this Services Tariff.

The ISO shall provide the preliminary results of its audit or review to the Market Monitoring Unit for its review and comment. The responsibilities of the Market Monitoring Unit that are addressed in this section of the Mitigation Measures are also addressed in Section 30.4.6.2.10 of Attachment O to this Service Tariff.

23.4.5.6.2.3 The audit and review of the removal of a Generator from a Forced Outage to an ICAP Ineligible Forced Outage, and the determinations of Catastrophic Failure and Exceptional Circumstances, will be pursuant to specific timelines established in ISO Procedures.

23.4.5.6.2.4 The audit and review pursuant to Sections 23.4.5.6.2.1, and 23.4.5.6.2.2 shall be conducted to determine whether the decision not to repair a Generator had a legitimate economic justification, consistent with competitive behavior; that is, whether the cost of repair, including the risk-adjusted cost of capital, could not reasonably be expected to be recouped over the reasonably anticipated remaining life of the Generator. The elements of such audit and review may include, as appropriate, the historical revenue and maintenance cost data for the purpose of the baseline, the duration of the repair, the costs including, but not limited to, capital expenditures necessary to comply with federal or state environmental, safety or reliability requirements that must be met in order to operate the Generator, the anticipated capacity, energy and ancillary services revenues following the repair, the projected costs of operating the Generator following the repair, any benefits that would be foregone from using the site for a purpose other than as the existing Generator (e.g., repowering), and other relevant data.

The criteria for the audit and review provided in this Services Tariff Section 23.4.5.6.2.4 may be incorporated, as appropriate, in an audit and review required to be conducted pursuant to other provisions in this Services Tariff Section 23.4.

23.4.5.6.2.5 For a requesting Market Participant, a determination that the Market Participant has experienced Exceptional Circumstances shall be made by the ISO by the 160th day of the Generator's Forced Outage. The ISO shall use reasonable efforts to issue a determination that a Market Participant has experienced Exceptional Circumstances after it has Commenced Repair and requests reclassification to an ICAP Ineligible Force Outage by the 40th day after the ISO's receipt of data necessary to conduct the analysis.

For a requesting Market Participant, a determination that a Generator has experienced a Catastrophic Failure shall be made by the ISO by the 160th day of the Forced Outage. If the ISO has determined that Exceptional Circumstances will delay the submission of data necessary for the ISO to perform an audit and review pursuant to Section 23.4.5.6.2.1 or 23.4.5.6.2, the ISO shall use reasonable efforts to issue a determination that the Generator has experienced a Catastrophic Failure by the 40th day after receipt of data necessary to conduct the analysis.

23.4.5.6.3 Penalties for Withholding Installed Capacity Physically In Order To Affect Prices

If the ISO determines that either: i) pursuant to Section 23.4.5.6.1, the proposal or decision by a Market Participant to retire or otherwise remove an Installed Capacity Supplier from a Mitigated Capacity Zone, or to de-rate the amount of Installed Capacity available from such supplier, or ii) pursuant to Section 23.4.5.6.2, the ISO determines that the reclassification of an Installed Capacity Supplier that is a Generator from a Forced Outage to an ICAP Ineligible Forced Outage constitutes physical withholding, and would increase the Market-Clearing Price in one or more ICAP Spot Market Auctions for a Mitigated Capacity Zone by five percent or

more, provided such increase is at least $.50/kilowatt-month, for each such violation of the above requirements the Market Participant shall be assessed an amount equal to the product of (A) 1.5 times the difference between the Market Clearing Price for the Mitigated Capacity Zone in the ICAP Spot Market Auctions with and without the inclusion of the withheld UCAP in those auctions, and (B) the total of (1) the number of megawatts withheld in the month and (2) all other megawatts of Installed Capacity in the Mitigated Capacity Zone under common Control with such withheld megawatts in the month. The requirement to pay such amounts shall continue until the Market Participant demonstrates that the removal from service, retirement, or de-rate, as described in Section 23.4.5.6.1, or reclassification as described in Section 23.4.5.6.2 is justified by economic considerations other than the effect of such action on Market-Clearing Prices in the ICAP Spot Market Auctions for the Mitigated Capacity Zone. The ISO will distribute any amount recovered in accordance with the foregoing provisions among the LSEs serving Loads in the Mitigated Capacity Zone(s) wherein the Market-Clearing Price was affected for the month corresponding to the penalty accordance with ISO Procedures.

23.4.5.6.4 Aligning Physical Withholding Audits and Reviews with the Short-Term Reliability Process

The rules in this Section 23.4.5.6.4 apply to Market Participants that initiate the Short-Term Reliability Process that is set forth in Attachment FF to the ISO OATT by submitting a Generator Deactivation Notice for a Generator. They provide an opportunity for such a Market Participant to receive a final physical withholding determination from the ISO before the Market Participant deactivates the Generator. Nothing in Attachment FF to the OATT or in this Section 23.4.5.6.4 of the ISO Services Tariff should be read as limiting the ISO’s authority to impose a physical withholding penalty on a Generator that deactivates. Capitalized terms that appear in

this Section 23.4.5.6.4 that are not defined in Article 2 to the ISO Services Tariff are defined in Section 38.1 of Attachment FF to the ISO OATT.

23.4.5.6.4.1 If the ISO has issued notice to the Market Participant or Generator Owner (as that term is defined in Section 38.1 of the ISO OATT) in accordance with Section 38.7.4 of Attachment FF to the ISO OATT that it has received all of the data and information it requires to perform its duties under both the Short-Term Reliability Process that is set forth in Attachment FF to the ISO OATT and Section 23 of the ISO Services Tariff, then the ISO shall complete a physical withholding review of the proposed deactivation, if needed, in accordance with Section 23.4.5.6 of the ISO Services Tariff and issue a final physical withholding determination to the Market Participant in accordance with the process set forth in Sections 23.4.5.6.4.2.1 or 23.4.5.6.4.2.2 of the ISO Services Tariff.

If the ISO has not issued a notice to the Market Participant or Generator Owner in accordance with Section 38.7.4 of Attachment FF to the ISO OATT that it has received all of the data and information it requires to perform its duties under both Attachment FF to the ISO OATT and Section 23 of the ISO Services Tariff, then the ISO is not required to issue a final physical withholding determination to the Market Participant for the Generator prior to the Generator's deactivation.

23.4.5.6.4.2 Aligning Issuance of Final Physical Withholding Determination with the Short-Term Reliability Process

23.4.5.6.4.2.1 **Based on deactivation date.** At least ninety days before the date the Generator determines it will timely (consistent with Section 38.14.1 of

Attachment FF to the ISO OATT) deactivate, the Market Participant (which is also a Market Party) may notify the ISO in writing of the updated deactivation date and request that the ISO issue a final physical withholding determination to the Market Participant, which shall be conducted by the ISO in accordance with Section 23.4.5.6.1 above. The ISO shall issue its final determination at least 60 days before the updated deactivation date specified in the Market Participant's written notice. For purposes of the ISO's audit or review to issue a final physical withholding determination, conducted in accordance with Section 23.4.5.6.1 above, the date on which the Generator is deactivated is the "decision date," so long as it falls within the 16 day window specified below.

Exception: The earliest date the ISO shall be required to issue a final physical withholding determination is 90 days after the Short-Term Assessment of Reliability Start Date.

The ISO's final physical withholding determination shall only be valid if the Generator becomes Retired or enters into a Mothball Outage within a window that starts five days before the date specified in the Market Participant's notice to the ISO and concludes ten days after the date specified in the Market Participant's notice to the ISO, unless the conditions of described below in Section 23.4.5.6.4.2.2 are met.

23.4.5.6.4.2.2 **Based on date of irrevocable action or inaction.** If the Market Participant identifies and the ISO, in consultation with the Market Monitoring Unit, agrees that there is a point in the process of deactivating a Generator after which the deactivation process will become, essentially and practicably,

irreversible, then the ISO shall inform the Market Participant in writing of the first such act, decision not to act, or event that the ISO agrees will have irreversible consequences.

The responsibilities of the Market Monitoring Unit that are addressed in this section of the Mitigation Measures are also addressed in Section 30.4.6.2.12 of Attachment O to this Services Tariff.

23.4.5.6.4.2.2.1 At least ninety days before the date the irreversible action, inaction or event specified by the ISO in its notice to the Market Participant will be taken, occur or come to pass (the "trigger date"), the Market Participant may notify the ISO in writing of the trigger date and request that the ISO issue a final physical withholding determination to the Market Participant. The Market Participant's notice must explain why the date it selected is the appropriate trigger date. If the ISO determines that the trigger date specified by the Market Participant is reasonable, then the ISO shall issue its final physical withholding determination at least 60 days before the trigger date specified in the Market Participant's notice. For purposes of the ISO's audit or review under this subsection conducted in accordance with Section 23.4.5.6.1 above, the trigger date is the "decision date."

Exception: The earliest date the ISO shall be required to issue a final physical withholding determination is 90 days after the Short-Term Assessment of Reliability Start Date.

23.4.5.6.4.2.2.2 If the ISO determines that the trigger date the Market Participant specified is not reasonable, then the ISO shall promptly notify the Market Participant of its determination and the reasons therefor in writing. The ISO is not

required to issue a final physical withholding determination unless the Market Party provides additional information within two business days of the issuance of the ISO's written determination that causes the ISO to change its decision.

23.4.5.6.4.2.2.3 The ISO's final physical withholding determination shall only be valid if (a) the specified irreversible action, inaction or event is taken or occurs within a window that starts five days before the trigger date specified in the Market Participant's notice to the ISO and concludes ten days after the trigger date specified in the Market Participant's notice to the ISO, and (b) the Generator timely (consistent with Section 38.14.1 of Attachment FF to the ISO OATT) enters into a Mothball Outage or becomes Retired. Except where the ISO possesses contrary information, the ISO shall accept the Market Participant's reasonable assessment of the date by which an irrevocable failure to act occurs.

23.4.5.6.4.3 The Market Participant shall promptly send a written notice to the ISO rescinding a written notice that it previously submitted under Sections 23.4.5.6.4.2.1 or 23.4.5.6.4.2.2.1 of the ISO Services Tariff if it determines that the deactivation date or trigger date it specified in its written notice to the ISO is no longer accurate.

23.4.5.6.5 Aligning Physical Withholding Audits and Reviews with the Transfer of Deliverability Rights Process for Same Location CRIS Transfers

The rules in this Section 23.4.5.6.5 apply to a Market Participant or Generator Owner that initiate a transfer of deliverability rights request as set forth in Attachment HH to the ISO OATT by submitting a CRIS transfer request notice for a same location transfer where the Market Participant/Generator Owner does not intend to initiate the Short Term Reliability Process that is

set forth in Attachment FF to the ISO OATT. They provide an opportunity for such a Market Participant to receive a final physical withholding determination from the ISO before the transfer of deliverability rights is confirmed under the rules set forth in Sections 40.18.3 and 40.18.4 of Attachment HH to the ISO OATT. Nothing in Attachment HH to the OATT or in this Section 23.4.5.6.5 of the ISO Services Tariff should be read as limiting the ISO's authority to impose a physical withholding penalty on a Generator that transfers its CRIS to a new facility at the same location.

23.4.5.6.5.1 If the ISO has issued notice to the Market Participant or Generator Owner in accordance with Section 23.4.5.6.5.3 of this Attachment H that it has received all of the data and information it requires to perform its duties under Section 23 of the ISO Services Tariff, then the ISO shall complete a physical withholding review of the proposed transfer of deliverability rights, if needed, in accordance with Section 23.4.5.6 of this Attachment H and issue a final physical withholding determination to the Market Participant in accordance with the process set forth in Section 23.4.5.6.5.5 of this Attachment H.

23.4.5.6.5.2 If the ISO has not issued a notice to the Market Participant or Generator Owner in accordance with Section 23.4.5.6.5.3 of this Attachment H to the ISO OATT that it has received all of the data and information it requires to perform its duties under Section 23 of the ISO Services Tariff, then the ISO is not required to issue a final physical withholding determination to the Market Participant prior to the CRIS Transfer Confirmation Date, as defined in Section 23.2.1 of this Attachment H, and as set forth in Section 40.18.3 and 40.18.4 of Attachment HH to the ISO OATT.

23.4.5.6.5.3 **ISO Notification to Market Participants or Generator Owners.** The ISO shall notify the Market Participant or the Generator Owner, in writing, when the ISO has received all of the data and information it requires as set forth in Section 23.4.5.6.5.4 of this Attachment H to perform its duties under Sections 23.4.5.6.5 of this Attachment H.

The notice that the ISO provides to Market Participant (which is also a Market Party) or to the Generator Owner that it has received all of the data and information it requires to perform its obligations under this Attachment H does not absolve the Market Party or the Generator Owner of its affirmative and continuing obligation under Section 23.4.5.6.5.5 of this Attachment H to supplement and update information and data it has submitted to the ISO when a material change in facts or circumstances occurs that makes the previously submitted information insufficient or inaccurate.

The notice that the ISO provides to Market Participant or Generator Owner that it has received all of the data and information it requires to perform its obligations under Sections 23.4.5.6.5 of this Attachment H does not bar the ISO from asking additional questions of the Market Participant or the Generator Owner, nor does it excuse the Market Participant or the Generator Owner from its continuing obligation to promptly respond to ISO requests for information or data pursuant to ISO Tariffs.

23.4.5.6.5.4 **Information Requirements**

23.4.5.6.5.4.1 The Market Participant or the Generator Owner (also known as the "transferor facility" as defined in Attachment HH to the ISO OATT) shall be

responsible for providing the ISO with any information that the ISO determines it requires, in accordance with ISO Procedures, in order to assess market impacts under Section 23.4.5.6.1 of this Attachment H.

23.4.5.6.5.4.2 The Second Party (also known as the "transferee facility" as defined in Attachment HH to the ISO OATT) shall be responsible for providing the ISO with any information that the ISO determines it requires, in accordance with ISO Procedures, in order to assess market impacts under Section 23.4.5.6.1 of this Attachment H.

23.4.5.6.5.4.3 The ISO shall review, verify and/or validate to the extent necessary the information provided in accordance with Sections 23.4.5.6.5.4.1 and 23.4.5.6.5.4.2 of this Attachment H. The ISO may reject, and may require to any of the involved Parties to re-submit, or substantiate information (including estimates) that the ISO determines is not adequately supported or otherwise verifiable. The Party shall promptly provide any additional information that the ISO may request, and update and revise information previously provided, and provide new information as set forth in Section 23.4.5.6.5.5 of this Attachment H.

Upon the ISO's request, the Parties involved shall make qualified representatives available to answer the ISO's question(s) and otherwise facilitate the ISO's review of the information. ISO may terminate its consideration for a physical withholding review if one of the Parties involved fails to provide requested information.

Note: If the Second Party (also known as the "transferee facility" as defined in Attachment HH to the ISO OATT) is subject to a Buyer Side

Mitigation Examination (as set forth in Sections 40.18.3 and 40.18.4 of Attachment HH to the ISO OATT) it must provide the ISO with any information that the ISO determines it requires regarding its Buyer Side Mitigation determination (as defined in Section 23.4.5.7 of this Attachment H), as part of the physical withholding determination request set forth in Section 23.4.5.6.5 of this Attachment H.

23.4.5.6.5.4.4 **Obligation to Submit Further Information.** (a) Market Participant or Generator Owner that requested a physical withholding determination in accordance with Section 23.4.5.6.1 of this Attachment H and (b) any other Second Party involved in the physical withholding determination request set forth in Section 23.4.5.6.5 of this Attachment H. shall provide any new information, and shall update and revise information previously submitted to the ISO in accordance with Section 23.4.5.6.5.4 of Attachment H, no more than ten days after any event occurring that makes any element of the information submitted materially inaccurate or insufficient.

23.4.5.6.5.5 Aligning Issuance of Final Physical Withholding Determination with the Transfer of Deliverability Rights Process for Same Location CRIS Transfers

23.4.5.6.5.5.1 At least ninety days prior to the CRIS Transfer Confirmation Date as set forth in Section 40.18.3 and 40.18.4 of Attachment HH to the ISO OATT, the Market Participant (which is also a Market Party) may notify the ISO in writing of the same location transfer of deliverability rights proposed confirmation and effective date and request that the ISO issue a final physical withholding determination to the Market Participant, which shall be conducted by the ISO in

accordance with Section 23.4.5.6.1 above. If the ISO, in consultation with the Market Monitoring Unit, determine that the CRIS Transfer Confirmation Date is, essentially and practicably, an irreversible point in the transfer process, then the ISO shall inform the Market Participant in writing and issue its final determination at least sixty days before the proposed CRIS Transfer Confirmation Date (as specified in the Market Participant's written notice).

The ISO's final physical withholding determination shall only be valid if the CRIS Transfer Confirmation Date becomes effective within a window that starts five days before the proposed effective date specified in the Market Participant's notice to the ISO and concludes ten days after the proposed effective date specified in the Market Participant's notice to the ISO.

23.4.5.6.5.5.2 A final physical withholding determination as specified in Section 23.4.5.6.6.1 of this Attachment H may only be requested by an active holder of CRIS rights as defined in Attachment HH to the ISO OATT.

23.4.5.7 Buyer-Side Market Power Mitigation Measures for Installed Capacity

Offers to supply Unforced Capacity from a Mitigated Capacity Zone Installed Capacity Supplier, unless from Excluded Facilities as defined in Section 23.2 or from facilities found to be exempt as specified below: (i) shall equal or exceed the applicable Offer Floor; and (ii) can only be offered in the ICAP Spot Market Auctions. Except for Offer Floors applied pursuant to Section 23.4.5.7.9.5.2 (i.e., after the revocation of a Competitive Entry Exemption), or Section 23.4.5.7.14.5 (*i.e.,* after the revocation of Self Supply Exemption), the ISP UCAP MW, or when the Installed Capacity Supplier is an RMR Generator, the Offer Floor shall apply to offers for Unforced Capacity from the Installed Capacity Supplier starting with the Capability Period for which the Installed Capacity Supplier first offers to supply UCAP. Offer Floors applied pursuant to Section 23.4.5.7.9.5.2 shall apply to offers for Unforced Capacity from an Installed Capacity Supplier starting with all ICAP auction activity subsequent to the date of the revocation. The same exemption determination or Offer Floor shall apply to the 2 MW or less that an existing Generator or UDR project with CRIS requests and receives under Section 40.5.6.6 (Attachment HH) of the ISO OATT. Offer Floors shall cease to apply:

(A) to that portion of an Examined Facility's UCAP (rounded down to the nearest tenth of a MW) that has cleared for any twelve, not-necessarily-consecutive, months (such cleared amount, "Cleared UCAP") in which the resource's MW were not ISP UCAP MW or MW of an RMR Generator: and

(B) for the period an Installed Capacity Supplier is an Interim Service Provider if its generating unit(s) are required to remain in-service but only in the amount of its ISP UCAP MW, or an RMR Generator in which case the Installed Capacity Supplier's offers of UCAP shall be as set forth in Section 23.4.5.7.12. Offer

Floors shall be adjusted annually using the most recent inflation rate that is the twelve month percentage change in the index for the general component of the escalation factor ("Inflation Rate") that is the most recent of (a) the Inflation Rate identified in the index accepted by the Commission after a periodic review in an ICAP Demand Curve Reset Filing Year, as of October 1 of the ICAP Demand Curve Reset Filing Year, and (b) the Inflation Rate in the Annual Update of the relevant effective ICAP Demand Curves published under Section 5.14.1.2.2.

(C) if the unit meets the criteria to be considered an Excluded Facility as defined in Section 23.2.

23.4.5.7.1 Unforced Capacity from (a) an Installed Capacity Supplier that is subject to an Offer Floor or (b) MW subject to an Offer Floor that are within a DER Aggregation may not be used to satisfy any LSE Unforced Capacity Obligation for Mitigated Capacity Zone Load unless such Unforced Capacity is obtained through participation in an ICAP Spot Market Auction.

23.4.5.7.2 An Examined Facility in a Mitigated Capacity Zone for which the Commission has accepted an ICAP Demand Curve shall be exempt from an Offer Floor if it has: (i) passed a Part A Exemption Test, as described in subsection (a) below for Offer Floor determinations issued by the ISO as part of any Class Year Study prior to Class Year 2023; or (ii) passed a Part A Exemption Test pursuant to Section 23.4.5.7.3.1 below for the Class Year immediately following Class Year 2021 and subsequently commenced Class Year Studies, Cluster Studies, Additional SDU Studies, and Expedited Deliverability Studies that are commenced after August 1, 2022; or (iii) passed a Part B Exemption Test as described below in subsection (b); or (iv) otherwise qualifies for the exemptions referenced in subsections (c) or (d) below:

(a) the price that is equal to the (x) average of the ICAP Spot Market Auction price for each month in the two Capability Periods, beginning with the Starting Capability Period, is projected by the ISO, in accordance with Section 23.4.5.7.15, to be higher than (y) the numerical value equal to 75 percent of the Mitigation Net CONE that would be applicable in the same two (2) Capability Periods (utilized to compute (x));

(b) the price that is equal to the average of the ICAP Spot Market Auction prices in the Mitigation Study Period is projected by the ISO, in accordance with Section 23.4.5.7.15, to be higher than the reasonably anticipated Unit Net CONE of the Examined Facility,

(c) it has been determined to be exempt pursuant to Section 23.4.5.7.9 (the "Competitive Entry Exemption"); or

(d) for an Examined Facility that participated in either a Class Year Study, Cluster Study, or an Additional SDU Study, it has been determined, and in the quantity of MW for which it has been determined, to be exempt pursuant to Section 23.4.5.7.14 (the "Self Supply Exemption").

For purposes of the determinations pursuant to (a) and (b) of this section, and determinations pursuant to Section 23.4.5.7.3.1 of the Services Tariff, the ISO shall identify Unit Net CONE and the projected ICAP Spot Market Auction prices in accordance with Section 23.4.5.7.15, for each Examined Facility promptly after it (i) has accepted its Project Cost Allocation (as defined below) and Deliverable MW, if any, from the Final Decision Round, and (ii) along with all other remaining members, has posted any associated Security pursuant to OATT Section 25 or 40 (OATT Attachment S or HH) (for purposes of Section 23.4, a Project that "remains a member of the completed Class Year Study, Cluster Study, Additional SDU Study, or Expedited Deliverability Study"), and it shall do so concurrently for an Expected CRIS Transferee (as defined in 23.2.1). If an Examined Facility passes the Part A Exemption Test pursuant to Section 23.4.5.7.3.1 and also passes the Part B Exemption Test described above in (b), it will be awarded a Part B Exemption; however, for the sole purposes of evaluating other Examined Facilities under the Part A Exemption Test and Part B Exemption Test, the capacity associated with the Examined Facility will continue to be treated as having received a Part A Exemption in order to ensure that another Examined Facility will not receive a Part A Exemption for the capacity of the

Examined Facility that was awarded the Part B Exemption after having passed both the Part A and Part B Exemption Tests.

For purposes of Section 23.4.5.7 *et seq*, "Project Cost Allocation" shall mean the singular Project Cost Allocation or two Project Cost Allocations (*i.e.*, one for System Deliverability Upgrades ("SDUs") and one for Connecting Transmission Owner's Attachment Facilities, Distribution Upgrades, and System Upgrade Facilities ("SUFs"), for the Project) from the Final Decision Round.

The first year value of an Examined Facility's Unit Net CONE calculated pursuant to Section 23.4.5.7 and Section 23.4.5.7.3.2, will be established in accordance with Section 23.4.5.7.3.7 at the time such Examined Facility first offers UCAP, and will be used by the ISO in subsequent mitigation exemption or Offer Floor determinations for Additional CRIS MW. A Unit Net CONE determination received pursuant to Sections 23.4.5.7.2, 23.4.5.7.6 or 23.4.5.7.7 shall only be final for the relevant Examined Facility, if the Project accepts its Project Cost Allocation or Deliverable MW requested by the Project, and the Project remains a member of the completed Class Year Study, Cluster Study, Additional SDU Study, or Expedited Deliverability Study on the date the ISO issues a notice to stakeholders that the Class Year Study, Cluster Study, Additional SDU Study, or Expedited Deliverability Study decisional process of which the Project is a member has been completed, and as specified in the ISO's notice to the Project of the final exemption and Offer Floor determinations for the quantity of CRIS MW accepted by the applicable Examined Facility or Examined Facilities in such Class Year Study, Cluster Study, Additional SDU Study, or

Expedited Deliverability Study at the time of its completion (or transferred CRIS if an Expected CRIS Transferee).

23.4.5.7.2.1 Promptly after Commission acceptance of the first ICAP Demand Curve to apply to a Mitigated Capacity Zone, the ISO shall make an exemption and Offer Floor determination for any NCZ Examined Project that has requested CRIS and remains a member of the completed Class Year Study, Cluster Study, Additional SDU Study, or Expedited Deliverability Study, or was an Expected CRIS Transferee and could have been evaluated concurrently with a Class Year Study or Cluster Study, and has received CRIS, unless exempt pursuant to section 23.4.5.7.6 or 23.4.5.7.8.

23.4.5.7.2.2 The ISO shall make an "Indicative Buyer-Side Mitigation Exemption Determination" for any NCZ Examined Project if (i) the Commission has accepted an ICAP Demand Curve for the Mitigated Capacity Zone that will become effective when the Mitigated Capacity Zone is first effective, or (ii) if the Commission has not accepted the first ICAP Demand Curve to apply specifically to the Mitigated Capacity Zone in which the NCZ Examined Project is located, provided the ISO has filed an ICAP Demand Curve pursuant to Services Tariff Section 5.14.1.2.2.4.11. The Indicative Buyer-Side Mitigation Exemption Determination shall be computed using such ICAP Demand Curve for the Mitigated Capacity Zone concurrent with the determinations the ISO makes for Examined Facilities pursuant to Sections 23.4.5.7.3.2 and 23.4.5.7.3.3. The ISO shall recompute the Indicative Buyer-Side Mitigation Exemption Determination promptly after Commission acceptance of the first ICAP Demand Curve for the

applicable Locality provided that such NCZ Examined Project (i) received CRIS if the Class Year or Cluster Study completed at the time the Commission accepts the Demand Curve, or (ii) has not been removed from the Class Year Deliverability Study or Cluster Study Deliverability Study if the Class Year or Cluster Study is not completed. The Indicative Buyer-Side Mitigation Exemption Determination is for informational purposes only. The exemption or Offer Floor for an NCZ Examined Project to which this Section applies shall be determined for such projects receiving CRIS using the Commission-accepted Locality ICAP Demand Curve.

23.4.5.7.2.3 Any NCZ Examined Project not exempt pursuant to 23.4.5.7.8 shall provide data and information requested by the ISO by the date specified by the ISO, in accordance with the ISO Procedures.

23.4.5.7.2.3.1 The ISO shall compute the reasonably anticipated ICAP Spot Market Auction forecast in accordance with Section 23.4.5.7.15.

23.4.5.7.2.4 When the ISO is evaluating more than one NCZ Examined Project concurrently, the ISO shall recognize in its computation of the anticipated ICAP Spot Market Auction forecast price that Generators or UDR projects will clear from lowest to highest, using for each NCZ Examined Project the lower of (i) the first year value of its Unit Net CONE, or (ii) the numerical value equal to 75 percent of the Mitigation Net Cone, then inflated in accordance with 23.4.5.7 for each of the year two and year three of the Mitigation Study Period. However, if a NCZ Examined Project elects to pursue an Additional SDU Study or an Expedited Deliverability Study and that study is not completed prior to the completion of the

current Class Year Study or Cluster Study then the NCZ Examined Project shall not be included in the BSM Forecast for the current Class Year Study or Cluster Study. If a NCZ Examined Project completes its Additional SDU Study after the completion of the Class Year Study or Cluster Study that it originally entered but before the time the ISO completes a subsequent Class Year's or Cluster Study's Cluster Baseline Assessment study cases then that NCZ Examined Project shall have a separate decisional process utilizing the Mitigation Study Period from the most recently completed Class Year Study or Cluster Study.

23.4.5.7.2.5 When evaluating NCZ Examined Projects pursuant to Sections 23.4.5.7.2.1 or 23.4.5.7.2.2, the ISO shall seek comment from the Market Monitoring Unit on matters relating to the determination of price projections and cost calculations. The ISO shall inform the NCZ Examined Project of the Offer Floor and/or Offer Floor exemption determinations or Indicative Buyer-Side Mitigation Exemption Determinations promptly. The responsibilities of the Market Monitoring Unit that are addressed in this Section 23.4.5.7.2.5 are also addressed in Section 30.4.6.2.13 of Attachment O to this Services Tariff.

23.4.5.7.2.6 If an NCZ Examined Project under the criteria in 23.4.5.7.2.1 or 23.4.5.7.2.2 does not provide all of the requested data by the date specified by the ISO, the MW of CRIS received at that time by the Project shall be subject to the Mitigation Net CONE Offer Floor for the period determined by the ISO in accordance with Section 23.4.5.7.

23.4.5.7.2.7 An NCZ Examined Project or Examined Facility located in more than one Mitigated Capacity Zone shall be evaluated pursuant to the tests in Section

23.4.5.7.2 (a) or 23.4.5.7.3.1 and (b) or 23.4.5.7.3 (as applicable), calculating Mitigation Net CONE for the smallest Mitigated Capacity Zone that contains the Load Zone in which such NCZ Examined Project or Examined Facility is electrically located.

23.4.5.7.3 The ISO shall make such exemption and Unit Net CONE determination for each Examined Facility that comprises a Project. When used in Section 23.4.5.7, the term "Generator" includes each Generator that plans to participate in a DER Aggregation.23.4.5.7.3.1 For Examined Facilities participating in Class Year 2023, and any subsequent Class Year Study, Cluster Study Additional SDU Study, and Expedited Deliverability Study that are commenced after August 1, 2022, the ISO shall conduct the Part A Exemption Test for all Examined Facilities in the manner described below prior to making any other exemption determinations under Sections 23.4.5.7.2(b), (c), and (d). If an Examined Facility passes the Part A Exemption Test described below and also passes the Part B Exemption Test described above in 23.4.5.7.2(b), it will be awarded a Part B Exemption; however, for the sole purposes of evaluating other Examined Facilities under the Part A Exemption Test and Part B Exemption Test, the capacity associated with the Examined Facility will continue to be treated as having received a Part A Exemption in order to ensure that another Examined Facility will not receive a Part A Exemption for the capacity of the Examined Facility that was awarded the Part B Exemption after having passed both the Part A and Part B Exemption Tests.

23.4.5.7.3.1.1 The ISO shall begin the Part A Exemption Test by dividing the Examined Facilities into Part A Group 1 Examined Facilities and Part A Group 2 Examined Facilities based upon the factors listed below in Section 23.4.5.7.3.1.3 of this Services Tariff and on the ISO's projection of the time frame when each Examined Facility will come into service. The ISO will post a list of each group

of Examined Facilities on its website in accordance with Section 23.4.5.7.3.1.4 of this Services Tariff. The ISO will rank all Examined Facilities in the Part A Group 1 Examined Facilities based upon the ISO's determination of each Examined Facility's specific Net Cost of New Entry except that all Public Policy Resources included in the Part A Group 1 Examined Facilities will be evaluated before other Part A Group 1 Examined Facilities. The ISO will rank all Examined Facilities in the Part A Group 2 Examined Facilities based upon the ISO's determination of each Examined Facility's specific Net Cost of New Entry except that all Public Policy Resources included in the Part A Group 2 Examined Facilities will be evaluated before other Part A Group 2 Examined Facilities. Each of the Examined Facilities in the Part A Group 1 Examined Facilities will be evaluated for the Part A Exemption Test using the Part A Mitigation Study Period Years 1 through 3. Upon completion of that evaluation, each of the Examined Facilities in the Part A Group 2 Examined Facilities will then be evaluated for the Part A Exemption Test using the Part A Mitigation Study Period Years 4 through 6.

23.4.5.7.3.1.2 For each Capability Year in a Part A Mitigation Study Period Years 1 through 3, the ISO will determine whether, in accordance with Section 23.4.5.7.15, the average ICAP Spot Market Auction price for each Capability Year in the Part A Mitigation Study Period Years 1 through 3 is higher than 75 percent of the Mitigation Net CONE that would be applicable to the Examined Facility during that same Capability Year. For any Capability Year in which this threshold is met, the Examined Facility will qualify for a Part A Exemption for

that Capability Year and any subsequent Capability Years. The Examined Facility, however, will be subject to an Offer Floor for any prior Capability Years in which the threshold was not met unless it otherwise qualifies for an exemption provided in 23.4.5.7.2 (b), (c), (d), or as Cleared UCAP. The Part A Exemption Test will be performed for each Examined Facility sequentially by rank. In its evaluation of each Examined Facility located in the New York City Locality for each Capability Year, the ISO will conduct the Part A Exemption Test for the New York City Locality prior to its evaluation for the G-J Locality. Following completion of review of all three Capability Years in the Part A Mitigation Study Period Years 1 through 3, this process is then conducted for the Part A Group 2 Examined Facilities for each Capability Year in the Part A Mitigation Study Period Years 4 through 6. The ISO will determine if, in accordance with Section 23.4.5.7.15, the average ICAP Spot Market Auction price for each Capability Year in the Part A Mitigation Study Period Years 4 through 6 is higher than 75 percent of the Mitigation Net CONE that would be applicable to the Examined Facility during that same Capability Year. If this threshold is met, the Examined Facility will qualify for a Part A Exemption for that Capability Year and any subsequent Capability Years. The Examined Facility, however, will be subject to an Offer Floor for any prior Capability Years in which the threshold was not met unless it otherwise qualifies for an exemption provided in 23.4.5.7.2 (b), (c), (d), or as Cleared UCAP. The Part A Exemption Test will be performed for each Examined Facility sequentially by rank. In its evaluation of each Examined Facility located in the New York City Locality for each Capability Year, the ISO

will conduct the Part A Exemption Test for the New York City Locality prior to its evaluation for the G-J Locality.

23.4.5.7.3.1.3 An Examined Facility will be in Part A Group 2 Examined Facilities unless: (i) it is already in-service; or (ii) the ISO has determined it (a) falls within a category of resources with a construction timeline of less than three years, including but not limited to small generators sized at or below 20 MW or uprates to existing generators and (b) is reasonable to project the facility could be in-service prior to the start of the second Winter Capability Period that falls within the Part A Mitigation Study Period Years 1 through 3. Those Examined Facilities that meet either (i) or (ii) above will be in Part A Group 1 Examined Facilities.

23.4.5.7.3.1.4 The ISO will post which Examined Facilities comprise the Part A Group 1 Examined Facilities and Part A Group 2 Examined Facilities 120 days after the Cluster Baseline Assessment lock down of any Class Year Study or Cluster Study; and 30 days after the start of any applicable Expedited Deliverability Studies.

23.4.5.7.3.2 The ISO shall compute the reasonably anticipated ICAP Spot Market Auction forecast price for any Mitigated Capacity Zone in accordance with Section 23.4.5.7.15.

When the ISO is evaluating more than one Examined Facility concurrently in either a Class Year Study, Cluster Study, Additional SDU Study or Expedited Deliverability Study, the ISO shall recognize in its computation of the anticipated ICAP Spot Market Auction forecast price that Generators or UDR projects will clear from lowest to highest, using for each Examined Facility the lower of (i) the

first year value of its Unit Net CONE, or (ii) the numerical value equal to 75 percent of the Mitigation Net Cone, then inflated in accordance with 23.4.5.7 for each of the year two and year three of the Mitigation Study Period. However, if an Examined Facility has accepted its determination from a Class Year Study, Cluster Study, Additional SDU Study, or Expedited Deliverability Study, then the Examined Facility shall also be included in the BSM Forecast for any subsequently completed Class Year Study, Cluster Study, Additional SDU Study, or Expedited Deliverability Study that utilized the same Mitigation Study Period that was used to evaluate the Examined Facility. If an Examined Facility completes its Additional SDU Study after the completion of the Class Year Study or Cluster Study that it originally entered but before the time the ISO completes a subsequent Class Year's or Cluster Study's Cluster Baseline Assessment study cases then that Examined Facility shall have a separate decisional process utilizing the Mitigation Study Period from the most recently completed Class Year Study or Cluster Study.

23.4.5.7.3.3 [Intentionally Left Blank]

All Interconnection Customers, and Installed Capacity Suppliers for any Examined Facility that do not request CRIS shall provide data and information requested by the ISO by the date specified by the ISO, in accordance with the ISO Procedures. For any such Examined Facility that is in a Class Year Study, Cluster Study, Additional SDU Study or Expedited Deliverability Study on the date the ISO issues a notice to stakeholders that the decisional period of which the Examined Facility is a member has been completed but that only has ERIS rights, the ISO shall utilize the data first provided in its analysis of the Unit Net CONE in its review of

the project in any future Class Year Study, Cluster Study, Additional SDU Study, or Expedited Deliverability Study in which the Generator or UDR project requests CRIS. The ISO shall determine the reasonably anticipated Unit Net CONE with the costs to be determined in the Project Cost Allocation, as applicable, prior to or contemporaneous with the commencement of the Initial Decision Round, and shall provide to the Examined Facility the ISO's initial determination of an exemption or the Offer Floor.

The ISO shall provide to each Examined Facility its price forecast and an initial determination (incorporating its revised Project Cost Allocation) prior to or contemporaneous with the commencement of the Initial Decision Round for the Class Year Study, Cluster Study, Additional SDU Study, and the Expedited Deliverability Study and for each Subsequent Decision Round for the Class Year Study, Cluster Study, and Additional SDU Study no later than the ISO's issuance of a Revised Project Cost Allocation for the Class Year Study, Cluster Study, and Additional SDU Study.

If an Examined Facility remains a member of the completed Class Year Study, Cluster Study, Additional SDU Study, or Expedited Deliverability Study, the ISO shall inform the Examined Facility of the final Offer Floor determination(s) or the Offer Floor exemption(s) that will apply to the Examined Facility as soon as practicable after the date the ISO issues a notice to stakeholders that the decisional period has been completed, in accordance with methods and procedures specified in ISO Procedures.

When evaluating Examined Facilities pursuant to this Section 23.4.5.7, the ISO shall seek comment from the Market Monitoring Unit on matters relating to the determination of price projections and cost calculations. The responsibilities of the Market Monitoring Unit that are

addressed in this section of the Mitigation Measures are also addressed in Section 30.4.6.2.13 of Attachment O to this Services Tariff.

23.4.5.7.3.4 If a Generator or UDR Project that would be an Examined Facility under the criteria provided in (II) of the Examined Facility definition in Section 23.2.1 has not provided written notice to the ISO on or before the Cluster Study Start Date for the Class Year Study or the Expedited Deliverability Study Start Date for the expedited Delivery Study with which it was eligible to examined, or any Examined Facility required to be reviewed does not provide all of the requested data by the date specified by the ISO, the proposed Capacity shall be subject to the Mitigation Net CONE Offer Floor for the period determined by the ISO in accordance with Section 23.4.5.7.

23.4.5.7.3.5 Except as specified in Section 23.4.5.7.6 with respect to Additional CRIS MW, an Examined Facility for which an exemption or Offer Floor determination has been rendered may only be reevaluated for an exemption or Offer Floor determination if it meets the criteria provided in (I) of the Examined Facility definition in Section 23.2.1 and was not previously in a Class Year Study, Cluster Study, Additional SDU Study, or Expedited Deliverability Study at the time of their completion and the Examined Facility either (a) enters a new Class Year or Cluster Study and requests CRIS or (b) intends to receive transferred CRIS rights at the same location. An Expected CRIS Transferee that received CRIS will be bound by the determination rendered and will not be reevaluated. An Examined Facility under the criteria that had been set forth in Section 23.4.5.7.3 (III) prior to May 19, 2016, will not be reevaluated.

23.4.5.7.3.6 In order to become an Examined Facility in an Expedited Deliverability Study an eligible Project must (1) provide a written request to the ISO's Market Mitigation and Analysis Department; and (2) satisfy all of the applicable data requirements in accordance with ISO Procedures prior to the start of the Expedited Deliverability Study. Once the data submission is deemed complete by the ISO the eligible Project will be notified by the ISO that it has satisfied the data requirements to enter an Expedited Deliverability Study.

23.4.5.7.3.7 If the Installed Capacity Supplier first offers UCAP prior to the first Capability Year of the Mitigation Study Period for which it was evaluated, its Offer Floor shall be reduced using the same numerical value for the inflation index that was used in the final determination issued under Section 23.4.5.7.4 (*i.e.*, when the Examined Facility remains a member of the completed Class Year or Cluster Study as identified in Section 23.4.5.7.4. If the Installed Capacity Supplier first offers UCAP after the first Capability Year of the Mitigation Study Period for which it was evaluated, its Offer Floor shall be increased using the inflation rate identified in 23.4.5.7.

23.4.5.7.3.8 Net Energy and Ancillary Services Revenue Projections for UDR Projects

For the purposes of making an exemption determination or Unit Net CONE determination pursuant to Section 23.4.5.7 for an Examined Facility that is a UDR project, the ISO will determine the likely projected net Energy and Ancillary Services revenues utilizing a methodology that reflects, as applicable, but is not limited to, the guiding principles set forth in Section 23.4.5.7.3.8.1. The ISO will implement this Section 23.4.5.7.3.8 in accordance with Section 23.4.5.7.3.8.2.

23.4.5.7.3.8.1 The methodology used for a specific UDR project shall reflect the following guiding principles, where applicable:

(a) The design and characteristics of the UDR project as proposed in the Class Year or Cluster Study, including whether it is proposed to be uni-directional or bi-directional.

(b) The market structure, scheduling rules, price formation rules, and other relevant characteristics and rules of the Control Area at each terminus of the UDR project.

(c) The reasonably projected effects of transactions utilizing the UDR project on NYCA and External Control Areas prices, including proxy bus prices.

(d) The reasonably projected cost to purchase energy, capacity, and ancillary services that would be transmitted into, and if the UDR project is proposed in the Class Year or Cluster Study to be bi-directional also from, the Mitigated Capacity Zone, utilizing the UDR project at the rate determined by: (i) market-based clearing price mechanisms to the extent that the External Control Area uses them, or ISO market prices if an internal UDR project; (ii) a reasonable substitute, in the ISO's judgment, to the extent that the External Control Area does not use market-based clearing price mechanisms to determine prices. The costs to purchase energy and capacity, and any other products associated therewith, shall not be based on advantages or sources of revenue that would not reflect arm's-length transactions, or that are not in ordinary course of business for a competitive energy market participant.

(e) The reasonably anticipated fees for transmitting the ISO-projected energy, capacity, and ancillary services transactions utilizing the UDR project. These fees

shall include any export fees, transmission services charges, ancillary services fees, scheduling fees, and other fees and costs.

(f) The reasonably projected opportunity costs (including fees) of selling energy, capacity, and any other products associated with the sale of energy, into an External Control Area in lieu of a sale transaction into the Mitigated Capacity Zone.

(g) The reasonably projected revenues from the sale of energy and ancillary services that would be transmitted into, and if the UDR project is proposed in the Class Year Study, Cluster Study, or Additional SDU Study to be bi-directional also from, the Mitigated Capacity Zone, utilizing the UDR project at the rate determined by: (i) market-based clearing price mechanisms to the extent that the External Control Areas uses them, or ISO market prices if an internal UDR project; (ii) a reasonable substitute, in the ISO's judgment, to the extent that the External Control Area does not use market-based clearing price mechanisms to determine prices. The revenues from the sale of energy, capacity, and any other products associated with the sale thereof, into an External Control Area shall not be based on advantages or sources of revenue that do not reflect arm's-length transactions, or that are not in ordinary course of business for a competitive energy market participant.

(h) The effect of scheduling uncertainty and imperfect arbitrage on the projected costs and revenues from the purchase and sale of energy and ancillary services that are reasonably projected to be transmitted into, and if the UDR project is

proposed in the Class Year Study, Cluster Study, or Additional SDU Study to be bi-directional also from, the Mitigated Capacity Zone, utilizing the UDR project.

23.4.5.7.3.8.2 Implementation

(a) The ISO shall seek comment from the Market Monitoring Unit on the methodology the ISO will use to project net Energy and Ancillary Services for each UDR project, and the inputs used to perform the calculation. The responsibilities of the Market Monitoring Unit that are addressed in this section are also addressed in Section 30.4.6.2.13 of Attachment O.

(b) The ISO shall post on its website a description of the methodology used for each UDR project, subject to any restrictions on the disclosure of Confidential Information or Critical Energy Infrastructure Information.

(c) If a Project withdraws from a Class Year Study, Cluster Study, or Additional SDU Study and then enters another Class Year or Cluster Study (regardless of whether it has the same or a different interconnection queue position), the ISO may utilize a different methodology than it previously used, provided it reflects, where applicable, the guiding principles set forth in Section 23.4.5.7.3.8.1 and implemented in accordance with Section 23.4.5.7.3.8.2(a) and (b).

23.4.5.7.4 For purposes of Sections 23.4.5.7.2(b) and 23.4.5.7.6(b), the ISO shall identify the Unit Net CONE projected for a Mitigation Study Period using: the most recent inflation index. For purposes of Section 23.4.5.7.4, the inflation index shall mean the average of the most recently published median Headline Consumer Price Index (CPI) and Headline Personal Consumption Expenditures (PCE) long-term annual averages for inflation over the ten years that includes the last year of the Mitigation Study Period, as reported by the Survey of Professional Forecasters, unless this index is eliminated, replaced or otherwise terminated by the publisher thereof. In such circumstance, the ISO shall utilize the replacement or successor index established by the publisher, if any, or, in the absence of a replacement or successor index, shall select as a replacement a substantially similar index.

23.4.5.7.5 Excluded Facility Certification

Certifications and Acknowledgments found in this section must be made on behalf of an Excluded Facility that asserts the project or Resource complies with the criteria specified in (i), (ii) and/or (iii) of the Excluded Facilities definition in Section 23.2 of the Services Tariff. Such an Excluded Facility shall be legally bound by the following Certification and Acknowledgement executed by a duly authorized officer:

CERTIFICATION AND ACKNOWLEDGMENT OF EXCLUDED FACILITY STATUS OF RESOURCE OR UDR PROJECT

I [NAME & TITLE] hereby certify on behalf of myself, [NAME OF RESOURCE/PROJECT], and [NAME OF INTERCONNECTION CUSTOMER/OWNER/OPERATOR] that each of the following statements is true and correct:

1. I am an officer whose responsibilities include the [development, ownership, or operational control] of [NAME OF RESOURCE/PROJECT], New York Independent System Operator, Inc.'s ("NYISO") [Queue Position/PTID Number (INSERT NUMBER)].

2. I am duly authorized to make representations concerning [NAME OF RESOURCE/PROJECT] for [NAME OF INTERCONNECTION CUSTOMER/OWNER/OPERATOR], including each of the certifications and acknowledgements that I have made in this document.

3. I hereby certify to the Excluded Facility Status of [NAME OF RESOURCE/PROJECT] as meeting the following criteria as provided in Section 23.2 of the Services Tariff in accordance with ISO Procedures and consistent with the documents provided in Schedule 1 of this Certification [select all that apply: i) the Resource technology type is specifically identified by the CLCPA or is publicly identified by New York State as supporting the goals of the CLCPA; (ii) the Resource or UDR project has a contract with the State of New York in order achieve the goals of the CLCPA (such as a Tier 1 or Tier 4 contract with NYSERDA); or (iii) the Resource or UDR project is eligible to receive a contract authorized by New York State that is supporting the goals of the CLCPA (such as a Tier 1 or Tier 4 contract with NYSERDA)].

4. I have reviewed and understand the requirements established under the NYISO Market Administration and Control Area Services Tariff ("Services Tariff") related to its Buyer Side Mitigation provisions described in Sections 23.2 and 23.4.5.7, *et seq* of the Services Tariff ("BSM Rules").

5. I have personal knowledge of the facts and circumstances supporting [NAME OF RESOURCE/PROJECT]'s status as an Excluded Facility pursuant to the NYISO's BSM Rules.

6. [Interconnection Customer/Owner/Operator] shall provide any information or cooperation requested by the NYISO in connection with this Certification and Acknowledgement of Excluded Facility Status.

I hereby acknowledge on behalf of myself, [NAME OF RESOURCE/PROJECT], and [NAME OF INTERCONNECTION CUSTOMER/OWNER/OPERATOR] that:

a. The submission of false, misleading, or inaccurate information, or the failure to submit information requested by the NYISO or to cooperate with a request related to this Certification and Acknowledgement, shall constitute a violation of Section 4.1.7 of the Services Tariff, and may be subject to the Commission's review, a violation of the Commission's regulations and Section 316A of the Federal Power Act.

b. If false, misleading, or inaccurate information is submitted, or requested information is not provided, including but not limited to information contained or submitted in this Certification and Acknowledgement, Excluded Facility status shall not be recognized for [NAME OF RESOURCE/PROJECT] which may potentially be subject to an Offer Floor in accordance with the BSM Rules unless it is otherwise determined to be exempt pursuant to Section 23.4.5.7.2(a) or (b) of the Services Tariff.

c. If the Project submits false, misleading, or inaccurate information, or fails to submit requested information to the NYISO or to cooperate with a request, including but not limited to information contained or submitted in the Certification and Acknowledgement on behalf of the Project, it may be subject to civil penalties that may be imposed by the Commission for violations of Section 4.1.7 of Services Tariff, the Commission's rules, and/or Section 316A of the Federal Power Act.

_____

[PRINT NAME]
[DATE]

Subscribed and sworn to before me
this [ ] day of [MONTH] [YEAR].

_____

Notary Public

My commission expires: _____

[PROJECT NAME] SCHEDULE 1 CERTIFICATION AND ACKNOWLEDGEMENT LIST AND ATTACHMENT OF PERTINENT DOCUMENTS AND AGREEMENTS
[DATE]

Source of Document/Parties to Agreement: _____

Title: _____

Date Issued/Executed: _____

23.4.5.7.5.1 Timing for Requests, Required Submittals, and Withdrawals

The executed Certification and Acknowledgement form required by Section 23.4.5.7.5 shall be submitted concurrent with a request to be considered an Excluded Facility. The ISO may request additional information or updated certifications at any time prior to the date that the Class Year or Cluster Study decisional process of which the Examined Facility is a member has been completed. Requests for Resources or UDR projects to be considered an Excluded Facility in Class Years or Cluster Studies and Requests for Resources to be considered an Excluded Facility in Expedited Deliverability Studies must be received by the ISO no later than the deadline by which a facility must notify the ISO of its election, as applicable, (A) to enter the Cluster Study, such date as set forth in Section 40.5.1 of OATT Attachment HH or (B) to enter the Class Year Study or Expedited Deliverability Study, such date as set forth in Section 25.5.9 OATT of Attachment S, except (i) that for members of the ongoing Class Year 2021 Study that must certify to their Excluded Facility Status, certification shall be submitted to the NYISO with the request to be considered as an Excluded Facility within twenty-one calendar days from [ ], the effective date of this tariff section and (ii) as noted in 23.4.5.7.5.1.1 below.

The ISO shall determine, in consultation with the Market Monitoring Unit, whether a Resource or UDR project is an Excluded Facility, subject to any required further submissions of information, prior to the Initial Decision Period within which an Interconnection Customer must provide an Acceptance Notice or Non-Acceptance Notice to the ISO in response to the first Project Cost Allocation issued by the ISO to the Interconnection Customer.

23.4.5.7.5.1.1 Existing Resources or UDR projects with an Offer Floor that was applied prior to Class Year 2021 Study may request at any time to be an Excluded Facility, consistent with ISO

Procedures. The ISO may request additional information at any time and updated certifications at any time for these requests prior to the issuance of a determination.

23.4.5.7.5.2 Notifications

The ISO shall post on its website a list of each Examined Facility that requests to be an Excluded Facility that becomes a member of the Class Year Study, Cluster Study, or Expedited Deliverability Study, promptly after, as applicable, (i) for a Cluster Study Process, the posting of the Cluster Study Project List as set forth in Section 40.7.2 of Attachment H of the OATT, (ii) for a Class Year Study, the deadline set forth in Section 30.8.1 of Attachment X of the OATT (by which the ISO must receive the Developer's executed Class Year Interconnection Facilities Study Agreement), or (iii) for an Expedited Deliverability Study, the deadline set forth in Section 25.5.9.2.2 of OATT Attachment S, or Section 40.19.3.2 of OATT Attachment HH, as applicable (by which the ISO must receive the Developer's executed Expedited Deliverability Study Agreement). The ISO shall also post on its website a list of all Examined Facilities that it determines to be Excluded Facilities at the conclusion of the associated Class Year Study, Cluster Study, Additional SDU Study, or Expedited Deliverability Study. The ISO shall update the list to reflect any changes.

23.4.5.7.5.3 False, Misleading, or Inaccurate Information

The submission of false, misleading, or inaccurate information, or the failure to submit requested information and cooperate in connection with a certification of Excluded Facilities status shall constitute a violation of the Services Tariff. Such violation shall be reported, by the ISO, to the Market Monitoring Unit and to the Commission's Office of Enforcement (or any successor to its responsibilities).

23.4.5.7.6 Exemption and Offer Floor Determinations for Additional CRIS MW:

All requests for Additional CRIS MW for an Examined Facility located in a Mitigated Capacity Zone, in a Class Year Study, Cluster Study, Additional SDU Study, Expedited Deliverability Study or through a transfer, shall be evaluated for a buyer-side mitigation exemption or Offer Floor in accordance with this Section 23.4.5.7.6 and with respect to requests for Competitive Entry Exemption in accordance with Section 23.4.5.7.9.6 and the applicable provisions of Section 23.4.5.7.9. Additional CRIS MW obtained in a Class Year Study, Cluster Study, Additional SDU Study, Expedited Deliverability Study or obtained through a transfer at the same location shall be exempt from an Offer Floor (a) if the price that is equal to (x) the average of the ICAP Spot Market Auction price for each month in the two Capability Periods, beginning with the Summer Capability Period commencing three years from the start of the Starting Capability Period is projected by the ISO, in accordance with Section 23.4.5.7.15, to be higher than (y) the highest Offer Floor based on the Mitigation Net CONE that would be applicable to such Additional CRIS MW in the same two (2) Capability Periods (utilized to compute (x)); (b) if the price that is equal to the average of the ICAP Spot Market Auction prices in the Mitigation Study Period is projected by the ISO, in accordance with Section 23.4.5.7.15, to be higher than the reasonably anticipated Unit Net CONE computed in accordance with (i) and (ii) of Section 23.4.5.7.6.1 for the Installed Capacity Supplier's Additional CRIS MW, or (c) for the quantity of MW determined to be exempt pursuant to Section 23.4.5.7.13 or 23.4.5.7.14 (*i.e.,* a Self Supply Exemption can be received for some Additional

CRIS MW that comprise all or part of the same request for Additional CRIS MW in a given Class Year Study, Cluster Study, Additional SDU Study, and Expedited Deliverability Study (except that Self Supply Exemptions are not available for projects evaluated as part of the Expedited Deliverability Study).

23.4.5.7.6.1 For Additional CRIS MW requested by an Examined Facility, when an exemption or Offer Floor is determined pursuant to this Section 23.4.5.7.6, the ISO shall compute Unit Net CONE as follows:

(i) Unit Net CONE for the Additional CRIS MW shall be based on the Additional CRIS MW and the costs and revenues of and associated with the Additional CRIS MW if:

(a) the prior final determination(s) concluded that the Installed Capacity for which the Examined Facility accepted CRIS was exempt from the Offer Floor pursuant to Section 23.4.5.7.2(b), 23.4.5.7.6(b), 23.4.5.7.7, or 23.4.5.7.8; or

(b) at the time of an Examined Facility's request for Additional CRIS MW: (1) it has accepted CRIS MW equal to, or greater than, 95 percent of the Examined Facility's maximum MW of electrical capability, net of auxiliary load, at an ambient temperature of 93° F as determined in accordance with ISO Procedures and (2) the amount of Cleared UCAP is greater than or equal to the amount of UCAP calculated pursuant to Section 23.4.5.7.6.3; or

(c) the Examined Facility's Total Evaluated CRIS MW includes exempted CRIS MW for which the Examined Facility did not receive a Unit Net CONE determination and thus did not provide data to the ISO because the determination

for the exempt CRIS MW received was not based on Unit Net CONE and was made prior to November 27, 2010.

(ii) or in all other cases, Unit Net CONE, shall be the greater of two values, one based on the Total Evaluated CRIS MW for the Examined Facility, and the costs and revenues of the Total Evaluated CRIS MW, and one based on the Additional CRIS MW, and the costs and revenues of the Additional CRIS MW.

23.4.5.7.6.2 When calculating the Unit Net CONE of the Total Evaluated CRIS MW for an Examined Facility, the ISO shall utilize the Examined Facility's first year Unit Net CONE determined pursuant to Section 23.4.5.7 and Section 23.4.5.7.3.2, adjusted to the year's dollars at the time of an Examined Facility's request for Additional CRIS MW using: (i) the relevant value from the price index for non-farm business output published in the Survey of Current Business by the Department of Commerce's Bureau of Economic Analysis ("BEA Non-Farm Price Index"), or its successor; or (ii) the most recent inflation rate determined pursuant to Section 5.14.1.2.2.4.11 for any future year which is beyond the published BEA Non-Farm Price Index, or its successor.

23.4.5.7.6.3 For purposes of making the determination pursuant to Section 23.4.5.7.6.1(i)(b)(2), the amount of Cleared UCAP shall be compared to an amount of UCAP calculated as the product of the CRIS MW held by the Examined Facility immediately prior to its request for Additional CRIS MW and (1-EFORd). Except as specified in the next paragraph, for purposes of this calculation, if the Examined Facility is a Generator, its EFORd shall be derived using the data in the 5-year average NERC-GADS Generating Availability

Report, or its successor, for the main class of the unit (hereinafter the "Class Average EFORd") that is current at the time of the request for Additional CRIS MW, when available. In all other cases, the ISO will apply the 5-year average derating factor from the ICAP/UCAP translation, for the smallest Mitigated Capacity Zone in which the resource is located at the time of the request. The EFORd applied by the ISO at the time that the Examined Facility first offers or certifies UCAP in an Installed Capacity auction ("Initial Entry EFORd") shall be used instead of Class Average EFORd when it is higher (*i.e.,* a greater outage rate) than the Class Average EFORd calculated at the time of the Examined Facility's request for Additional CRIS MW.

23.4.5.7.6.4 Additional CRIS MW shall be subject to the Mitigation Net CONE Offer Floor for the period specified in Section 23.4.5.7, for any Examined Facility whose Total Evaluated CRIS MW includes CRIS MW that are or have ever been subject to the Mitigation Net CONE Offer Floor, pursuant to Section 23.4.5.7.3.4.

23.4.5.7.6.5 The Offer Floor for Additional CRIS MW shall be equal to the lesser of: (a) the Unit Net CONE for the Additional CRIS MW; or (b) a numerical value equal to 75 percent of the Mitigation Net CONE translated into a seasonally adjusted monthly UCAP value for the Additional CRIS MW.

23.4.5.7.6.6 The results of this exemption determination shall apply only to the Additional CRIS MW and shall not alter or affect any prior exemption or Offer Floor determination for the Examined Facility. The Additional CRIS MW for which CRIS is received shall be bound by the determination rendered and will not

be reevaluated unless the Examined Facility enters a new Class Year for the Additional CRIS MW.

23.4.5.7.6.7 When the ISO makes a mitigation exemption or Offer Floor determination for an Examined Facility's Additional CRIS MW for an Installed Capacity Supplier other than that to which the Unit Net CONE determination for the Examined Facility was rendered, the ISO shall provide such Installed Capacity Supplier with the Examined Facility's first year Unit Net CONE value if the Installed Capacity Supplier (a) requests that information, and (b) represents that it: (i) will use that information solely for purposes of considering a request for Additional CRIS MW for the Examined Facility, and (ii) will not share that information with or make it available to any other person except those that are assisting it in considering a request for Additional CRIS MW.

23.4.5.7.6.8 The ISO shall post on its website the determination of whether the project is exempt or non-exempt from an Offer Floor as soon as the determination is final. Concurrent with the ISO's posting, the Market Monitoring Unit shall publish a report on the ISO's determination, as further specified in Section 30.4.6.2.13 of Attachment O to this Services Tariff.

23.4.5.7.6.9 For Additional CRIS MW requested by an Examined Facility, the ISO may consider any shared costs when determining the methodology for calculating the Unit Net CONE for Additional CRIS MW in accordance with Section 23.4.5.7.6.1 above.

23.4.5.7.7 An Installed Capacity Supplier or UDR project that is an Excluded Facility shall not be subject to an Offer Floor. An In-City Installed Capacity Supplier that was an existing facility on or before March 7, 2008 shall be exempt from an Offer Floor with respect to the MW of CRIS that it had as of that date unless the CRIS subsequently expired under Section 25.9.3.1 or 40.18.2.1 of the ISO OATT. A Generator or UDR project that was an existing facility on or before June 29, 2012, which: (i) is in a Mitigated Capacity Zone except New York City, and (ii) was grandfathered from the deliverability requirement at a certain quantity of MW of CRIS pursuant to Section 25.9.3.1 of Attachment S or Section 40.18.2.1 of Attachment HH to the OATT ("Deliverability Grandfathering Process") shall be exempt from an Offer Floor for the MW quantity of CRIS that was provided through the Deliverability Grandfathering Process plus an additional 2 MW obtained through Section 30.3.2.6 of Attachment X or Section 40.5.6.6 of Attachment HH to the OATT unless the CRIS subsequently expired under Section 25.9.3.1 or 40.18.2.1 of the ISO OATT. If the Generator or UDR project subsequently received CRIS either (I) after the expiration of its CRIS (under Section 25.9.3.1 or 40.18.2.1 of the ISO OATT) to which the exemption under this Section 23.4.5.7.7 applied or (II) above the quantity established through the Deliverability Grandfathering Process, this exemption shall not apply to any such increase above the 2 MW allowed in Section 30.3.2.6 of Attachment X or Section 40.5.6.6 of Attachment HH to the OATT.

23.4.5.7.8 For any Mitigated Capacity Zone except New York City:

(I) Any existing or proposed Generator or UDR project that is not an Excluded Facility and that has the characteristics specified in this Section 23.4.5.7.8(I) shall be exempt from an Offer Floor with respect to the MW of CRIS that it received at the time, or for which it satisfied the specific CRIS transfer requirements stated in this Section. To be eligible for an exemption under this Section: (a) the existing or proposed Generator or UDR project's location must be included in the ISO's March 31 Filing in the ICAP Demand Curve Reset Filing Year in which a Mitigated Capacity Zone is first applied to such location; (b) prior to that March 31 Filing the existing or proposed Generator or UDR project must have both: (i) Commenced Construction and (ii) either (1) received the MW of CRIS in a Class Year or Cluster Study that was completed or (2) submitted to the ISO an Interconnection Request that specifically states that the Generator or UDR project will be requesting or has requested a transfer of a specific MW quantity of CRIS at the same location in accordance with Section 25.9.4 of Attachment S or 40.18.3 of Attachment HH to the OATT (provided that the transfer is ultimately approved by the ISO and consummated); and (c) the existing or proposed Generator or UDR project must demonstrate to the ISO no later than the deadline established by the ISO that it satisfies the requirements of (b) (i) and (ii) above; and

(II) An existing or proposed Generator or UDR project that is not an Excluded Facility and that is not subject to a deliverability requirement (and therefore, is not in a Class Year or Cluster Study and does not receive CRIS MW) shall be exempt from an Offer Floor if it meets the following requirements prior to the ISO's

March 31 Filing in an ICAP Demand Curve Reset Filing Year in which a Mitigated Capacity Zone is first applied to such location: (a) has Commenced Construction, (b) has an effective interconnection agreement, and (c) provides specific written notification to the ISO that it meets requirements (a) and (b) of this subsection 23.4.5.7.8(II) no later than the deadline established by the ISO.

The ISO shall consult with the Market Monitoring Unit prior to determining whether an existing or proposed Generator or UDR project has Commenced Construction. Prior to the ISO making its determination, the Market Monitoring Unit shall provide the ISO a written opinion and recommendation regarding whether an existing or proposed Generator or UDR project Commenced Construction. The responsibilities of the Market Monitoring Unit that are addressed in this section of the Mitigation Measures are also addressed in Section 30.4.6.2.13 of Attachment O. The ISO shall only make a determination pursuant to this Section for an existing or proposed Generator or UDR project for the Mitigated Capacity Zone's first application to the location of the project. The Market Monitoring Unit shall also provide a public report on its assessment of an ISO determination that an existing or proposed Generator or UDR project is exempt from an Offer Floor pursuant to this Section 23.4.5.7.8.

23.4.5.7.9 Competitive Entry Exemption

23.4.5.7.9.1 Eligibility

The eligibility of an Examined Facility, except an Examined Facility that has made a request for Additional CRIS MW, to request and receive a Competitive Entry Exemption is governed by Sections 23.4.5.7.9.1 through 23.4.5.7.9.5. The eligibility of an Examined Facility that that has made a request for Additional CRIS MW to request and receive a Competitive Entry Exemption is governed by Sections 23.4.5.7.9.6 and otherwise as referenced in Section 23.4.5.7.9.1 and Sections 23.4.5.7.9.2.2 through 23.4.5.7.9.5 except as expressly excluded.

23.4.5.7.9.1.1 An Examined Facility that becomes a member of a Class Year Study or Cluster Study after Class Year 2012 or is a member of an Expedited Deliverability Study may request to be evaluated for a "Competitive Entry Exemption" for its CRIS MW and shall qualify for such exemption if the ISO determines that the proposed Examined Facility meets each of the following requirements: (a) it does not have, and at no time before the Examined Facility that is a Generator first produces or that is a UDR project first transmits energy (for purposes of this Section 23.4.5.7.9, the "Entry Date") shall have, (i) a direct or indirect "non-qualifying contractual relationship," as defined in Section 23.4.5.7.9.1.2, with a "Non-Qualifying Entry Sponsors"; or (ii) an unexecuted agreement, written or unwritten, with a Non-Qualifying Entry Sponsor that would support the development of the project, except those agreements that would not constitute a "non-qualifying contractual relationship," as set forth in Section 23.4.5.7.9.1.3(i) – (viii), (b) is not itself, and is not an Affiliate of, a Non-Qualifying Entry Sponsor.

23.4.5.7.9.1.2 For purposes of Section 23.4.5.7.9, a direct "non-qualifying contractual relationship" shall include but not be limited to any contract, agreement, arrangement, or relationship (for the purposes of this Section 23.4.5.7.9, a "contract") of the Interconnection Customer or any Affiliate of the Interconnection Customer of the Examined Facility that is the subject of the request for a Competitive Entry Exemption that: (a) directly relates to the planning, siting, interconnection, operation, or construction of the Examined Facility; (b) is for the energy or capacity produced by or delivered from or by the Examined Facility, including an agreement for rights to schedule or use a UDR; or (c) provides services, financial support, or tangible goods to the Examined Facility, its Interconnection Customer, or Affiliates which could benefit the Interconnection Customer, its Affiliates, the Examined Facility, or potential future Additional CRIS MW associated with it. For purposes of Section 23.4.5.7.9, an indirect "non-qualifying contractual relationship" is any contract between the Interconnection Customer of the Examined Facility or its Affiliate and an entity (for purposes of this Section 23.4.5.7.9, a "third party") if the third party has a non-qualifying contractual relationship with a Non-Qualifying Entry Sponsor that states that it will benefit, or which the ISO determines has the purpose or effect of benefitting, at the time of the Competitive Entry Exemption evaluation or thereafter (including after an Examined Facility or Additional CRIS MW enters the market), (i) any portion of the Examined Facility, or its Interconnection Customer/Owner (ii) the owner of the site on which the Examined Facility is

located, (iii) any facilities, equipment, or personnel shared by an Examined Facility and another entity.

23.4.5.7.9.1.3 A contract with a Non-Qualifying Entry Sponsor shall not constitute a "non-qualifying contractual relationship" if it is (i) an interconnection agreement; (ii) an agreement for the construction or use of interconnection facilities or transmission or distribution facilities, or directly connected joint use transmission or distribution facilities (including contracts required for compliance with Articles VII or 10 of the New York State Public Service Law or orders issued pursuant to Articles VII or 10); (iii) a grant of permission by any department, agency, instrumentality, or political subdivision of New York State to bury, lay, erect or construct wires, cables or other conductors, with the necessary poles, pipes or other fixtures in, on, over or under public property; (iv) a contract for the sale or lease of real property to or from a Non-Qualifying Entry Sponsor at or above fair market value as of the date of the agreement was executed, such value demonstrated by an independent appraisal at the time of execution prepared by an accountant or appraiser with specific experience in such valuations; (v) an easement or license to use real property; (vi) a contract, with any department, agency, instrumentality, or political subdivision of New York State providing for a payment-in-lieu of taxes (*i.e.*, a "PILOT" agreement) or industrial or commercial siting incentives, such as tax abatements or financing incentives, provided the PILOT agreement or incentives are generally available to industrial or commercial entities; (vii) a service agreement for natural gas entered into under a tariff accepted by a regulatory body with jurisdiction over that service; or (viii) a

service agreement entered into under a tariff accepted by a regulatory body with jurisdiction over that service at a regulated rate for electric Station Power, or steam service, excluding an agreement for a rate that is a negotiated rate pursuant to any such regulated electric, or steam tariff; or (ix) a contract that is determined by the ISO, and that is certified in accordance with Section 23.4.5.7.9.6.6 to be a Competitive and Non-Discriminatory Hedging Contract. Notwithstanding the foregoing, a contract with a Non-Qualifying Entry Sponsor that includes a provision that is a non-qualifying contractual relationship will render the entire contract described in (i) through (ix) of this Section a non-qualifying contractual relationship.

23.4.5.7.9.1.4 The ISO shall determine whether an Examined Facility is eligible for a Competitive Entry Exemption based on its review of the certifications required by Section 23.4.5.7.9.2 for a proposed new Examined Facility and Section 23.4.5.7.9.6.5 for requests for Additional CRIS MW, below, and any other supporting data requested by the ISO. When evaluating eligibility for a Competitive Entry Exemption, the ISO shall consult with the 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 30.4.6.2.13 of Attachment O to this Services Tariff.

23.4.5.7.9.2 Certifications and Acknowledgements

Certifications and Acknowledgments that must be made on behalf of Examined Facilities, except for Examined Facilities that have requested Additional CRIS MW, in order to receive a Competitive Entry Exemption, are governed by Sections 23.4.5.7.9.2.1 (and otherwise as

referenced in Section 23.4.5.7.9). Certifications and Acknowledgments that must be made on behalf of Examined Facilities that have requested Additional CRIS MW Examined Facilities, in order to receive a Competitive Entry Exemption, are governed by Sections 23.4.5.7.9.6.5 (and otherwise as referenced in Section 23.4.5.7.9 except as expressly excluded). Additional Certifications and Acknowledgements that must be made on behalf of Examined Facilities that assert that a contract should be deemed to be a Competitive and Non-Discriminatory Hedging Contract are governed by Section 23.4.5.7.9.6.6.

23.4.5.7.9.2.1 An Examined Facility (except an Examined Facility requesting Additional CRIS MW) requesting a Competitive Entry Exemption shall submit to the ISO in accordance with ISO Procedures, and shall be legally bound by, the following Certification and Acknowledgement executed by a duly authorized officer:

CERTIFICATION AND ACKNOWLEDGMENT

I [NAME & TITLE] hereby certify on behalf of myself, [NAME OF PROJECT], and [NAME OF INTERCONNECTION CUSTOMER] that each of the following statements is true and correct:

1. I am an officer whose responsibilities include the development of the [EXAMINED FACILITY], New York Independent System Operator, Inc.'s ("NYISO") Queue Position Number [INSERT NUMBER] (the "Project").

2. I am duly authorized to make representations concerning the Project [INTERCONNECTION CUSTOMER/OWNER, and INTERCONNECTION CUSTOMER's/OWNER's AFFILIATES], including each of the certifications and acknowledgements that I have made in this document.

3. I hereby [REQUEST ON BEHALF OF/ACKNOWLEDGE THE PRIOR SUBMISSION IN THIS CLASS YEAR STUDY, ADDITIONAL SDU STUDY, or EXPEDITED DELIVERABILITY STUDY BY] the Interconnection Customer a Competitive Entry Exemption for the Project.

4. I have reviewed and I understand the requirements established under the NYISO Market Administration and Control Area Services Tariff ("Services Tariff") related to a "Competitive Entry Exemption" pursuant to Section 23.4.5.7.9.

5. I have personal knowledge of the facts and circumstances supporting the Project's request and eligibility for a Competitive Entry Exemption as of the date of this Certification and Acknowledgment, including all data and other information submitted by the Project to the NYISO.

6. To the best of my knowledge and having conducted due diligence that is current as of the date of this Certification there [ARE/ARE NOT ANY] direct or indirect contractual relationships with a "Non-Qualifying Entry Sponsor," as those terms are defined in Section 23.4.5.7.9 of the Services Tariff. I have listed all contracts of the Project, Interconnection Customer/Owner and all of its Affiliates with Non-Qualifying Entry Sponsors on Schedule 1 to this Certification including those that have expired or been terminated, and those for which performance remains to be completed.

7. If the Answer to (6) is that there are one or more direct or indirect contractual relationships for the Project with a Non-Qualifying Entry Sponsor, then I certify that to the best of my knowledge and having conducted due diligence that they are "allowable contracts" as set forth in Section 23.4.5.7.9.1.3(i) – (ix) of the Services Tariff. For each such contractual relationship, I have identified on Schedule 1 to this Certification the subsection(s) of 23.4.5.7.9.1.3(i) – (ix) which causes the contractual relationship to be an "allowable contract."

8. To the best of my knowledge and having conducted due diligence that is current as of the date of this Certification, (a) no unexecuted agreements, written or unwritten, with a Non-Qualifying Entry Sponsor exist that would support the development of the Project, the Interconnection Customer/Owner, or an Affiliate that directly or indirectly could reasonably be expected to benefit the Project except those agreements that would not constitute a non-qualifying contractual relationship, as set forth in Section 23.4.5.7.9.1.3(i) – (ix) of the Services Tariff, (b) all such written agreements and a description of all such unwritten agreements is set forth on Schedule 2 to this certification, and (c) none of the foregoing would constitute a non-qualifying contractual relationship. For each such unexecuted agreement I have identified on Schedule 2 to this certification the specific tariff subsection(s) of (i) – (ix) which causes the contractual relationship to be an "allowable contract."

9. To the best of my knowledge and having conducted due diligence, the Project is not a Non-Qualifying Entry Sponsor, and it is not an "Affiliate" (as Affiliate is defined in Section 2.1 of the Services Tariff) of, a Non-Qualifying Entry Sponsor.

10. The Interconnection Customer/Owner shall provide any information or cooperation requested by the NYISO in connection with the Project's request for a Competitive Entry Exemption.

11. All parents or Affiliates of the Project shall provide any information or cooperation requested by the ISO.

I hereby acknowledge on behalf of myself, [INSERT NAME OF PROJECT], and [NAME OF INTERCONNECTION CUSTOMER/OWNER] that:

a. The submission of false, misleading, or inaccurate information, or the failure to submit information requested by the NYISO or to cooperate with a request related to the Project's request for a Competitive Entry Exemption, including but not limited to information contained or submitted in this Certification and Acknowledgement on behalf of the Project, shall constitute a violation of Section 4.1.7 of the Services Tariff, and subject to the Commission's review, a violation of the Commission's regulations and Section 316A of the Federal Power Act.

b. If the Project submits false, misleading, or inaccurate information, or fails to submit requested information to the NYISO or to cooperate with a request, including but not limited to information contained or submitted in this Certification and Acknowledgement on behalf of the Project, it shall cease to be eligible for a Competitive Entry Exemption and, if the Project has already received a Competitive Entry Exemption, that exemption shall be subject to revocation by the NYISO or the Commission after which the Project shall potentially be subject to an Offer Floor as specified under Section 23.4.5.7.9.5 starting with the date of the revocation pursuant to Section 23.4.5.7.9.5.3 of the Services Tariff unless otherwise determined to be exempt pursuant to Section 23.4.5.7.2(a) or (b) of the Services Tariff.

c. If the Project submits false, misleading, or inaccurate information, or fails to submit requested information to the NYISO or to cooperate with a request, including but not limited to information contained or submitted in the Certification and Acknowledgement on behalf of the Project, it may be subject to civil penalties that may be imposed by the Commission for violations of Section 4.1.7 of Services Tariff, the Commission's rules, and/or Section 316A of the Federal Power Act.

_____

[PRINT NAME]
[DATE]

Subscribed and sworn to before me
this [ ] day of [MONTH] [YEAR].

_____

Notary Public

My commission expires: _____

PROJECT NAME] SCHEDULE 1 CERTIFICATION AND ACKNOWLEDGEMENT [DATE]

Parties to agreement Date Executed Effective Date Date Performance Commences

23.4.5.7.9.2.2 A duly authorized officer of the Generator or UDR project shall also submit a certification acknowledging that parents or Affiliates shall provide any information or cooperation requested by the ISO.

23.4.5.7.9.2.3 The certifying officers must have knowledge of the facts and circumstances supporting the request and qualification for a Generator's or UDR project's Competitive Entry Exemption.

23.4.5.7.9.2.4 Such certifications shall be submitted concurrent with the request for a Competitive Entry Exemption, (a) each time there is a proposed new contract, an executed new contract, or an amendment, revision, or addendum (or any similar change) to an executed or unexecuted contract, with a Non-Qualifying Entry Sponsor, and (b) each time the ISO requests a resubmittal of a certification, until the Examined Facility project's Entry Date.

23.4.5.7.9.2.5 The Interconnection Customer or Owner of the Examined Facility must notify the ISO if information in a certification ceases to be true, within two (2) business days after the earlier of the date that it learned that the information had ceased to be true or the date that it should have reasonably determined that the information was likely no longer to be true.

23.4.5.7.9.2.6 Failure to provide, without prior notification (such notification as described in Section 23.4.5.9.2.7 below), information or cooperation consistent with any certification shall be considered a false, misleading, or inaccurate submission for purposes of Section 23.4.5.7.9.5.

23.4.5.7.9.2.7 Where a written notification that information requested by the ISO or cooperation with a request will not be provided is received by the ISO's Market Mitigation and Analysis Department, within two (2) business days of an Interconnection Customer /Owner or its Affiliate's receipt of the ISO's request, such refusal shall not be considered a false, misleading, or inaccurate submission for purposes of Section 23.4.5.7.9.5 as long as the information and cooperation is provided by the earlier of a mutually agreed upon deadline or fifteen (15) calendar days. A failure by any other party to any such contract to provide any consent that might be necessary to disclose it or associated information to the ISO shall not excuse the Interconnection Customer/Owner and its Affiliates from their obligations hereunder. A failure to provide a Certification and Acknowledgement in accordance with Sections 23.4.5.7.9.2.1, 23.4.5.7.9.2.4 and 23.4.5.7.9.2.5, any refusal to provide information, cooperation, or any other failure to provide information or cooperation by the deadline will (a) make the Examined Facility requesting a Competitive Entry Exemption in that Class Year or Cluster Study and ineligible to request a Competitive Entry Exemption in the future, whether in a Class Year or Cluster Study or as an Expected CRIS Transferee (in either case, under the same Queue Position number or a different Queue Position number), and (b) constitute a violation of the Services Tariff. Such violation shall be

reported, by the ISO, to the Market Monitoring Unit and to the Commission's Office of Enforcement (or any successor to its responsibilities). The Examined Facility will receive a determination of exempt or non-exempt (and if the latter, an Offer Floor) under Sections 23.4.5.7.2(a) or (b) and 23.4.5.7.6(a) or (b) provided that the Examined Facility's (or its Affiliate's) failure under this Section does not also constitute a failure under Section 23.4.5.7.3.4 of the Services Tariff.

23.4.5.7.9.3 Timing for Requests, Required Submittals, and Withdrawals

23.4.5.7.9.3.1 The executed Certification and Acknowledgement form required by Section 23.4.5.7.9.2 shall be submitted concurrent with a request for a Competitive Entry Exemption. The ISO may request additional information at any time and updated certifications at any time prior to the latter of the Examined Facility's Entry Date or the date that the Class Year or Cluster Study decisional process of which the Examined Facility is a member has been completed (or in the case of an Examined Facility that is an expected recipient of transferred CRIS rights, such Class Year or Cluster Study along with which it is being examined). An Examined Facility that is granted a Competitive Entry Exemption pursuant to this Section 23.4.5.7.9, shall be required to submit an executed Certification and Acknowledgement form set forth in Section 23.4.5.7.9.2 or Section 23.4.5.7.9.6.5, as applicable of the Services Tariff, updated when required by or upon request from the ISO pursuant to Section 23.4.5.7.9.2.4, until its Entry Date.

23.4.5.7.9.3.2 Requests for Competitive Entry Exemptions for Generators or UDR projects in Class Years or Cluster Studies subsequent to Class Year 2012 and Requests for Competitive Entry Exemptions for Generators in Expedited

Deliverability Studies must be received by the ISO no later than the deadline by which a facility must notify the ISO of its election, as applicable, (A) to enter the Cluster Study, such date as set forth in Section 40.5.1 of OATT Attachment HH or (B) to enter the Class Year Study or Expedited Deliverability Study, such date as set forth in Section 25.5.9 OATT Attachment S, except as noted below. If the Examined Facility is a request for transferred CRIS at the same location and a determination under Section 25.9.4 of Attachment S or Section 40.18.3 of Attachment HH to the OATT has been made that it does not need to be a member of a Class Year or Cluster Study, then the request for a Competitive Entry Exemption must be received by the election date of the Class Year or Cluster Study with which the Examined Facility will be examined under Section 23.4.5.7. With respect to Class Year 2019, requests for Competitive Entry Exemptions may be submitted after the deadline specified in the first sentence of this Section 23.4.5.7.9.3.2 within fifteen (15) calendar days of the day of the Commission's issuance of an order accepting revisions to Section 23.4.5.7.9 of the Services Tariff that were filed with the Commission on [December 20, 2019]. A Generator or UDR project that requests a Competitive Entry Exemption in a Class Year Study or Cluster Study or a Generator that requests a Competitive Entry Exemption in an Expedited Deliverability Study may not also request a Self Supply Exemption. An Examined Facility (except a request for Additional CRIS) that remains a member of the completed Class Year if such Class Year is Class Year 2012 or prior Class Year, shall not be eligible to request or receive a Competitive Entry Exemption. The ISO shall determine whether an Examined

Facility is exempt, subject to any required further submissions of information, or not exempt under the Competitive Entry Exemption, prior to the Initial Decision Round within which an Interconnection Customer must provide an Acceptance Notice or Non-Acceptance Notice to the ISO in response to the first Project Cost Allocation issued by the ISO to the Interconnection Customer.

23.4.5.7.9.3.3 An Examined Facility that submits a request for a Competitive Entry Exemption, including the required Certification and Acknowledgement, responses to information requests, and resubmittal, but (a) enters into a "non-qualifying contractual relationship" or (b) enters into an unexecuted agreement, written or unwritten, with a Non-Qualifying Entry Sponsor that would support the development of the Project, except those agreements identified in 23.4.5.7. 9.1.3 that would not constitute a "non-qualifying contractual relationship, may withdraw such request, provided that it notifies the ISO that it has entered into such "non-qualifying contractual relationship" within two (2) business days of doing so. An Examined Facility that withdraws its Competitive Entry Exemption request by this deadline shall remain eligible to obtain an exemption under Section 23.4.5.7.2(a) or (b) and 23.4.5.7.6(a) or (b) if the criteria of those provisions are satisfied. If an Examined Facility enters into the kind of impermissible arrangement described above and seeks to withdraw its request before the Class Year or Cluster Study Initial Decision Round commences, but does not seek to withdraw until after this provision's deadline, then it shall be subject to the lesser of the Mitigation Net CONE Offer Floor or Unit Net CONE Offer Floor (such value calculated based on the date that it first offers UCAP, in

accordance with Section 23.4.5.7.3.7, and adjusted annually in accordance with Section 23.4.5.7 of the Services Tariff,) but will not be subject to the provisions of Section 23.4.5.7.9.5.

23.4.5.7.9.4 Notifications

23.4.5.7.9.4.1 The ISO shall post on its website a list of each Examined Facility that requests a Competitive Entry Exemption that becomes a member of the Class Year Study, Expedited Deliverability Study or Cluster Study promptly after, as applicable, (i) for a Cluster Study Process, the posting of the Cluster Study Project List as set forth in Section 40.7.2 of Attachment H of the OATT, (ii) for a Class Year Study the deadline set forth in Section 30.8.1 of the OATT (Attachment X) (by which the ISO must receive the Developer's executed Class Year Interconnection Facilities Study Agreement), or (iii) (ii) for an Expedited Deliverability Study, the deadline set forth in Section 25.5.9.2.2 of OATT Attachment S, or Section 40.19.3.2 of OATT Attachment HH, as applicable (by which the ISO must receive the Developer's executed Expedited Deliverability Study Agreement). The ISO shall update the list as necessary. The ISO shall also post on its website whether a request for a Competitive Entry Exemption was denied, or granted, as soon as its determination is final.

23.4.5.7.9.4.2 Concurrent with the ISO posting of its final determination, the Market Monitoring Unit shall publish a report on the ISO's determination in accordance with Section 30.4.6.2.13 of Attachment O to this Services Tariff.

23.4.5.7.9.5 Revocation

23.4.5.7.9.5.1 The submission of false, misleading, or inaccurate information, or the failure to submit requested information and cooperate in connection with a request for a Competitive Entry Exemption shall constitute a violation of the Services Tariff. Such violation shall be reported, by the ISO, to the Market Monitoring Unit and to the Commission's Office of Enforcement (or any successor to its responsibilities).

23.4.5.7.9.5.2 Where the ISO reasonably believes that a request for a Competitive Entry Exemption was granted based on false, misleading, or inaccurate information, the ISO shall notify the Examined Facility (or if no longer an Examined Facility, the Interconnection Customer/Owner of the Generator, UDR project or Additional CRIS MW) that its Competitive Entry Exemption may be revoked, and provided 30 days written notice has been given to the Examined Facility (such notice to the extent practicable,) the ISO may revoke the Competitive Entry Exemption. If the ISO revokes the Competitive Entry Exemption it shall determine whether the Generator, UDR project, or Additional CRIS MW is nevertheless exempt from an Offer Floor under Section 23.4.5.7.2(a) or (b) or 23.4.5.7.6(a) or 23.4.5.7.6(a), unless the failure that led to the revocation is also a failure under 23.4.5.7.3.4. If the Generator, UDR project, or Additional CRIS MW does not qualify for such an exemption it shall be subject to the lesser of the Mitigation Net CONE Offer Floor or Unit Net CONE Offer Floor (such value calculated based on the date that the MW was first offered as UCAP, in accordance with Section 23.4.5.7.3.7, and adjusted annually in accordance with Section 23.4.5.7 of the Services Tariff.)

Prior to the revocation of a Competitive Entry Exemption and the submission of a report to the Commission's Office of Enforcement (or any successor to its responsibilities,) the ISO shall provide the Examined Facility (or if no longer an Examined Facility, the Interconnection Customer/Owner of the Generator, UDR project or Additional CRIS MW) an opportunity to explain any statement, information, or action. The ISO cannot revoke the Competitive Entry Exemption until after the 30 days written notice period has expired, unless ordered to do so by the Commission.

23.4.5.7.9.6 Competitive Entry Exemption Requests for Additional CRIS MW

23.4.5.7.9.6.1 An Examined Facility shall be eligible to request a Competitive Entry Exemption for Additional CRIS MW if:

(a) the most recent prior final determination in a completed Class Year or Cluster Study concluded that the Capacity for which the Examined Facility accepted CRIS was exempt from an Offer Floor under Sections 23.4.5.7.2(b), 23.4.5.7.6(b), 23.4.5.7.7 (with respect to MW of CRIS that the Examined Facility had at that time unless the CRIS subsequently expired under Section 25.9.3.1 or 40.18.2.1 of the ISO OATT), 23.4.5.7.8, or 23.4.5.7.9 (except for an Examined Facility for which an exemption was revoked under Section 23.4.5.7.9.5.2); or (b) (i) it has accepted CRIS MW equal to, or greater than, 95 percent of the Examined Facility's maximum MW of electrical capability, net of auxiliary load, at an ambient temperature of 93° F as determined in accordance with ISO Procedures; and (ii) the amount of Cleared UCAP is greater than or equal to the amount of UCAP calculated pursuant to Section 23.4.5.7.6.3; or

(c) the Examined Facility's Total Evaluated CRIS MW includes exempted CRIS MW for which the Examined Facility did not receive a Unit Net CONE determination and thus did not provide data to the ISO because the determination for the exempt CRIS MW received was not based on Unit Net CONE and was made prior to November 27, 2010.

23.4.5.7.9.6.2 An Examined Facility that requests Additional CRIS MW and that requests a Competitive Entry Exemption in accordance with Sections 23.4.5.7.9.3.1 and 23.4.5.7.9.3.2 shall qualify for such exemption if the ISO makes the determination specified in Section 23.4.5.7.9.1.1, *i.e.,* that the Examined Facility does not have a direct or indirect "non-qualifying contractual relationship" as defined in Sections 23.4.5.7.9.1.2 and 23.4.5.7.9.1.3 with one or more Non-Qualifying Entry Sponsors as defined in Section 23..2.1 However, an Examined Facility would not be disqualified from obtaining a Competitive Entry Exemption for Additional CRIS MW if prior to the date on which the exemption request and Certification and Acknowledgment were due and were made in accordance with Sections 23.4.5.7.9.3.1 and 23.4.5.7.9.3.2 of this Services Tariff the Examined Facility had a non-qualifying contractual relationship under which (a) full performance has been completed by all parties, or (b) all obligations of each party to all other parties were terminated or expired,.

23.4.5.7.9.6.3 An Examined Facility that obtains a Competitive Entry Exemption for Additional CRIS MW must maintain compliance with the requirements of Section 23.4.5.7.9 until the later of: (i) the Examined Facility demonstrating, in accordance with ISO Procedures, that its generating capacity or total transfer

capability has increased from the uprate associated with the Additional CRIS MW; and (ii) the date that the Class Year or Cluster Study decisional process of which the Examined Facility is a member has been completed (or in the case of an Examined Facility that is an Expected CRIS transferee , the date that the transfer is effective).

23.4.5.7.9.6.4 An Examined Facility that requests Additional CRIS MW and that requests a Competitive Entry Exemption shall also be subject to the requirements of Sections 23.4.5.7.9.2.2 through 23.4.5.7.9.5. The ISO shall likewise follow the requirements of Section 23.4.5.7.9.2 through 23.4.5.7.9.5 when making Competitive Entry Exemption determinations for Additional CRIS MW. In the event of a conflict between the application of Sections 23.4.5.7.9.6 and Sections 23.4.5.7.9.2 through 23.4.5.7.9.5 to a Competitive Entry Exemption request for Additional CRIS MW, the requirements of Section 23.4.5.7.9.6 will control.

23.4.5.7.9.6.5 An Examined Facility that requests Additional CRIS MW and that requests a Competitive Entry Exemption shall submit to the ISO in accordance with ISO Procedures, and shall be legally bound by, the following Certification and Acknowledgement executed by a duly authorized officer:

ADDITIONAL CRIS MW CERTIFICATION AND ACKNOWLEDGMENT

I [NAME & TITLE] hereby certify on behalf of myself, [NAME OF EXAMINED FACILITY ON THE QUEUE], and [NAME OF DEVELOPER] that each of the following statements is true and correct:

1. I am an officer whose responsibilities include the development of the [ADDITIONAL CRIS MW APPLICABLE TO EXAMINED FACILITY], New

York Independent System Operator, Inc.'s ("NYISO") Queue Position Number [INSERT NUMBER – if applicable].

2. I am duly authorized to make representations concerning the Additional CRIS MW and the [INTERCONNECTION CUSTOMER and INTERCONNECTION CUSTOMER's AFFILIATES], including each of the certifications and acknowledgements that I have made in this document.

3. I hereby [REQUEST ON BEHALF OF/ACKNOWLEDGE THE PRIOR SUBMISSION IN THIS CLASS YEAR/CLUSTER STUDY BY] a Competitive Entry Exemption for the Additional CRIS MW.

4. I have reviewed and I understand the requirements established under the NYISO Market Administration and Control Area Services Tariff ("Services Tariff") related to a "Competitive Entry Exemption Request for Additional CRIS MW" pursuant to Section 23.4.5.7.9.6.

5. I have personal knowledge of the facts and circumstances supporting the request and eligibility for a Competitive Entry Exemption for the Additional CRIS MW as of the date of this Certification and Acknowledgment, including all data and other information submitted by the [OWNER OF THE GENERATOR OR UDR FACILITY REQUESTING ADDITIONAL CRIS MW] to the NYISO.

6. To the best of my knowledge and having conducted due diligence that is current as of the date of this Certification there [ARE/ARE NOT ANY] direct or indirect contractual relationships with a "Non-Qualifying Entry Sponsor," as those terms are defined in Section 23.4.5.7.9 of the Services Tariff. I have listed all contracts of the Project, Interconnection Customer and all of its Affiliates with Non-

Qualifying Entry Sponsors on Schedule 1 to this Certification including those that have expired or been terminated, and those for which performance remains to be completed.

7. If the Answer to (6) is that there are one or more direct or indirect contractual relationships with a Non-Qualifying Entry Sponsor, then I certify that to the best of my knowledge and having conducted due diligence that they are "allowable contracts" as set forth in Section 23.4.5.7.9.1.3(i) – (ix) of the Services Tariff. For each such contractual relationship, I have identified on Schedule 1 to this Certification the subsection(s) of 23.4.5.7.9.1.3(i) – (ix) which causes the contractual relationship to be an "allowable contract."

8. To the best of my knowledge and having conducted due diligence that is current as of the date of this Certification, (a) no unexecuted agreements, written or unwritten, with a Non-Qualifying Entry Sponsor exist that would support the development of the Additional CRIS MW, or the Interconnection Customer or its Affiliate, that directly or indirectly could reasonably be expected to benefit the Examined Facility except those agreements that would not constitute a non-qualifying contractual relationship, as set forth in Section 23.4.5.7.9.1.3(i) – (ix) of the Services Tariff, and (b) all such written agreements and a description of all such unwritten agreements is set forth on Schedule 2 to this certification, and (c) none of the foregoing would constitute a non-qualifying contractual relationship. For each such unexecuted agreement I have identified the specific tariff subsection(s) of (i) – (ix) which causes the contractual relationship to be an "allowable contract".

9. To the best of my knowledge and having conducted due diligence, the [INTERCONNECTION CUSTOMER] is not a Non-Qualifying Entry Sponsor, and it is not an "Affiliate" (as Affiliate is defined in Section 2.1 of the Services Tariff) of, a Non-Qualifying Entry Sponsor.

10. The [INTERCONNECTION CUSTOMER] shall provide any information or cooperation requested by the NYISO in connection with the request for a Competitive Entry Exemption for the Additional CRIS MW.

11. All parents or Affiliates of the [OWNER OF THE GENERATOR OR UDR FACILITY REQUESTING ADDITIONAL CRIS MW] shall provide any information or cooperation requested by the ISO.

I hereby acknowledge on behalf of myself, [INSERT NAME OF THE GENERATOR OR UDR FACILITY REQUESTING ADDITIONAL CRIS MW], and [OWNER OF THE GENERATOR OR UDR FACILITY REQUESTING ADDITIONAL CRIS MW] that:

a. The submission of false, misleading, or inaccurate information, or the failure to submit information requested by the NYISO or to cooperate with a request related to the request for a Competitive Entry Exemption, including but not limited to information contained or submitted in this Certification and Acknowledgement for the [OWNER OF THE GENERATOR OR UDR FACILITY REQUESTING ADDITIONAL CRIS MW] that requested Additional CRIS MW, shall constitute a violation of Section 4.1.7 of the Services Tariff, and subject to the Commission's review, a violation of the Commission's regulations and Section 316A of the Federal Power Act.

b. If [OWNER OF THE GENERATOR OR UDR FACILITY REQUESTING ADDITIONAL CRIS MW] submits false, misleading, or inaccurate information, or fails to submit requested information to the NYISO or cooperate with a request, including but not limited to information contained or submitted in this Certification and Acknowledgement on behalf of the Additional CRIS MW, or to cooperate with a request it shall cease to be eligible for a Competitive Entry Exemption and, if a Competitive Entry Exemption has already been granted for the Additional CRIS MW, that exemption shall be subject to revocation by the NYISO or the Commission after which the Additional CRIS MW shall potentially be subject to an Offer Floor set at the Mitigation Net CONE Offer Floor as specified under Section 23.4.5.7.9.5 starting with the date of the revocation pursuant to Section 23.4.5.7.9.5.3 of the Services Tariff.

c. If [OWNER OF THE GENERATOR OR UDR FACILITY REQUESTING ADDITIONAL CRIS MW] submits false, misleading, or inaccurate information, or fails to submit requested information to the NYISO, including but not limited to information contained or submitted in the Certification and Acknowledgement, it may be subject to civil penalties that may be imposed by the Commission for violations of Section 4.1.7 of Services Tariff, the Commission's rules, and/or Section 316A of the Federal Power Act.

_____

[PRINT NAME]

[DATE]

Subscribed and sworn to before me

this [ ] day of [MONTH] [YEAR].

_____

Notary Public

My commission expires: _____

[NAME OF OWNER OF THE EXAMINED FACILITY REQUESTING ADDITIONAL CRIS MW AND PROJECT NAME OF THE ADDITIONAL CRIS MW EXAMINED FACILITY NAME]

SCHEDULE 1 CERTIFICATION AND ACKNOWLEDGEMENT

[DATE]

Parties to agreement **Date Executed** **Effective Date** **Date Performance Commences**

23.4.5.7.9.6.6 An Examined Facility that requests that a contract be deemed to be a Competitive and Non-Discriminatory Hedging Contract must obtain the following certification and acknowledgment from the entity that awarded the contract and must ensure that that the certification and acknowledgement is submitted to the ISO in accordance with ISO Procedures. If the Examined Facility does not submit the required certification and acknowledgement the contract will not qualify as a Competitive and Non-Discriminatory Hedging Contract. If the entity that awarded the contract makes false, misleading, or inaccurate statements in the certification and acknowledgement that the Examined Facility knew, or reasonably should have known, were false, misleading, or inaccurate then the Examined Facility shall be deemed to have made a false and misleading statement to the ISO in violation of Section 4.1.7 of the Services Tariff, and subject to the Commission's review, a violation of the Commission's regulations and Section 316A of the Federal Power Act. Such violations may subject the Examined Facility to civil penalties under the Federal Power Act. In addition, if information submitted by the Entity is false, misleading, or inaccurate or if either the Examined Facility or the entity that submits the information fails to submit required information, or to cooperate with a request for information from the ISO pertaining to the certification and acknowledgement, then the Examined Facility shall cease to be eligible for a Competitive Entry Exemption. If a Competitive Entry Exemption has already been granted that exemption shall be subject to revocation by the ISO or the Commission under Section 23.4.5.7.9.5.

CERTIFICATION AND ACKNOWLEDGMENT FOR COMPETITIVE AND NON-DISCRIMINATORY HEDGING CONTRACTS

I [NAME & TITLE] hereby certify on behalf of myself and [NAME OF ENTITY THAT PROCURED HEDGING CONTRACT] that each of the following statements is true and correct:

1. I am an officer whose responsibilities include the solicitation and procurement of the contract (or contracts) that is (or are) the subject of this statement.
2. I am duly authorized to make representations concerning [ENTITY's] solicitation and procurement of the relevant contract(s).
3. I have reviewed and I understand the requirements established under the NYISO Market Administration and Control Area Services Tariff ("Services Tariff") related to a "Competitive Entry Exemption" pursuant to Section 23.4.5.7.9 of the Services Tariff [or, if applicable, "Competitive Entry Exemption Request for Additional CRIS MW" pursuant to Section 23.4.5.7.9.6.], including the requirements under Section 23.2 that must be met before a contract may be deemed to be a "Competitive and Non-Discriminatory Hedging Contract."
4. I have personal knowledge of the facts and circumstances regarding the solicitation and procurement of the contract[s] that [NAME OF EXAMINED FACILITY AND INTERCONNECTION CUSTOMER] is [are] requesting be treated as [a] Competitive and Non-Discriminatory Hedging Contract[s] as of the date of this Certification and Acknowledgment. These contracts are identified in Schedule I to this Certification and Acknowledgment.

5. To the best of my knowledge and having conducted due diligence that is current as of the date of this Certification and Acknowledgment, each contract identified in Schedule I was executed through a solicitation and procurement process that met all of the following requirements (which are the requirements specified in Section 23.2 of the Services Tariff): (A) both new and existing resources could satisfy the requirements of the procurement; (B) the requirements of the procurement were fully objective and transparent; (C) the contract was (or will be) awarded based on the lowest cost offers of qualified bidders; (D) the procurement terms did not restrict the type of capacity resources that may participate in, and satisfy the requirements of, the procurement; (E) the procurement terms did not include selection criteria that could otherwise give preference to new resources; and (F) the procurement terms did not use indirect means to discriminate against existing resources, including, but not limited to, by imposing geographic constraints, unit fuel requirements, maximum unit heat-rate requirements or requirements for new construction
6. [ENTITY] shall provide any information or cooperation requested by the NYISO in connection with its determination of whether the contracts I have identified in Schedule I shall be deemed to be Competitive and Non-Discriminatory Hedging Contracts.

I hereby acknowledge on behalf of myself and [ENTITY] that:

a. The submission of false, misleading, or inaccurate information, or the failure to submit information requested by the NYISO, including but not limited to

information contained or submitted in this Certification and Acknowledgement or to cooperate with a request from the NYISO related to this Certification and Acknowledgment, shall constitute a violation of Section 4.1.7 of the Services Tariff, and subject to the Commission's review, a violation of the Commission's regulations and Section 316A of the Federal Power Act. These violations may subject [ENTITY] to civil penalties under the Federal Power Act.

b. If information contained or submitted in this Certification and Acknowledgment is false, misleading, or inaccurate, or the [PROJECT OR EXAMINED FACILITY REQUESTING ADDITIONAL CRIS MW OWNER] fails to submit requested information to the NYISO or cooperate with a request, pertaining to information contained or submitted in this Certification and Acknowledgement, then the [PROJECT OR EXAMINED FACILITY REQUESTING ADDITIONAL CRIS MW OWNER] shall cease to be eligible for a Competitive Entry Exemption. If a Competitive Entry Exemption has already been granted that exemption shall be subject to revocation by the NYISO or the Commission after which the Examined Facility [if applicable -- Additional CRIS MW] shall potentially be subject to an Offer Floor set at the Mitigation Net CONE Offer Floor as specified under Section 23.4.5.7.9.5 starting with the date of the revocation pursuant to Section 23.4.5.7.9.5.3 of the Services Tariff.

_____

[PRINT NAME]

[DATE]

Subscribed and sworn to before me

this [ ] day of [MONTH] [YEAR].

_____

Notary Public

My commission expires: _____

[NAME OF OWNER OF THE EXAMINED FACILITY REQUESTING COMPETITIVE AND NON-DISCRIMINATORY HEDGING CONTRACT STATUS [NAME]

SCHEDULE 1 CERTIFICATION AND ACKNOWLEDGEMENT

[DATE]

Parties to agreement	**Date Executed**	**Effective Date**	**Date Performance Commences**

23.4.5.7.10 The ISO shall post on its website the identity of the Examined Facility in a Mitigated Capacity Zone and the determination of either exempt or non-exempt as soon as the determination is final. Concurrent with the ISO's posting, the Market Monitoring Unit shall publish a report on the ISO's determinations, as further specified in Section 30.4.6.2.13 of Attachment O to this Services Tariff.

23.4.5.7.11 Mitigated UCAP that is subject to an Offer Floor shall remain subject to the requirements of Section 23.4.5.4. Except as set forth in 23.4.5.7.12, and if the Offer Floor is higher than the applicable Mitigated UCAP offer cap, the (a) Installed Capacity Supplier shall submit offers equal to the applicable Offer Floor, and (b) if the Mitigated UCAP is associated with a DER Aggregation that includes MW subject to an Offer Floor, the Installed Capacity Supplier shall submit offers for the MW subject to the Offer Floor equal to the applicable Offer Floor.

23.4.5.7.12 An Interim Service Provider that is required to keep its generating unit(s) in-service and that has UCAP subject to an Offer Floor shall offer all ISP UCAP MW in each ICAP Spot Market Auction at $0.00/kW-month. For an RMR Generator that has UCAP subject to an Offer Floor, the UCAP subject to the Offer Floor shall be offered at $0.00/kW-month.

23.4.5.7.13 [Reserved for Future Use]

23.4.5.7.14 Self Supply Exemption

23.4.5.7.14.1 Eligibility

23.4.5.7.14.1.1 In order to be evaluated for a Self Supply Exemption the Examined Facility must be a member of a Class Year Study, Cluster Study, or Additional SDU Study, cannot participate in an Expedited Deliverability Study, and each of the following requirements must be satisfied, by the deadline, in the required form, and with the required information in accordance with ISO Procedures. If one or more of the requirements is not satisfied, the ISO shall not evaluate the request for a Self Supply Exemption.

(a) An Interconnection Customer or Owner of an Examined Facility, NCZ Examined Project, or Additional CRIS MW, (for purposes of this Section 23.4.5.7.14 an "SSE Applicant") may request to be evaluated for a Self Supply Exemption for a specified quantity of MW up to the amount of the CRIS MW requested in the Class Year or Cluster Study or, of which it is the expected recipient of transferred CRIS rights at the same location, in accordance with ISO Procedures. The ISO will evaluate the request if the SSE Applicant is a member of a Class Year or Cluster Study after Class Year 2019 and its request is received no later than the deadline by which a facility must notify the ISO of its election to enter the Class Year or Cluster Study, such date as set forth in Section 25.5.9 OATT Attachment S or Section 40.5.1 of OATT Attachment HH, as applicable, or (iii) an expected recipient of transferred CRIS rights at the same location and the ISO has been notified, by the transferor or the transferee, of a transfer pursuant to Section 25.9.4 of Attachment S or Section 40.18.3 of Attachment HH to the OATT that will be effective on a date within the Mitigation Study Period for the Class Year or Cluster Study, provided

that the request is received no later than the Cluster Study Start Date An Examined Facility or an NCZ Examined Project that is a member of a Class Year or Cluster Study may not request a Self Supply Exemption in the same Class Year or Cluster Study that it requests a Competitive Entry Exemption, and an Examined Facility or an NCZ Examined Project that is the expected transferee of CRIS being considered with a Class Year or Cluster Study may not request a Self Supply Exemption in respect of the same Class Year or Cluster Study that it requests a Competitive Entry Exemption

A proposed new Generator or UDR project that remained a member of Class Year 2012 or a prior Class Year at the time of the completion of such Class Year, shall not be eligible to request or receive a Self Supply Exemption except in relation to a request for Additional CRIS MW.

(b) If the SSE Applicant is not the wholly owned property of the Self Supply LSE(s), or the wholly owned property of an entity that is wholly owned by the Self Supply LSE(s) or that wholly owns the Self Supply LSE(s), it must have a Long Term Contract (in accordance with Subsection (1) of this Section 23.4.5.7.14.1.1(b)(1) with the Self Supply LSE(s) that shall obligate the SSE Applicant to provide the capacity forming the basis for its eligibility for a Self Supply Exemption. Such an SSE Applicant must make its Self Supply Exemption request jointly, in a single request, with the Self Supply LSE(s) with which it has a Long Term Contract. If the proposed SSE Applicant is the wholly owned property of the Self Supply LSE(s), or the wholly owned property of an entity that is wholly owned by the Self Supply LSE(s) or that wholly owns the Self Supply LSE(s), then the SSE Applicant must provide documentation at the time it requests the exemption that demonstrates to the reasonable satisfaction of the ISO that it has a statutory,

regulatory, or organizational obligation to provide Energy and Capacity to meet the Self Supply LSE's (or Self Supply LSEs') ICAP Obligation(s).

(1) Long Term Contract: For the purposes of a Self Supply Exemption, a "Long Term Contract" shall mean (i) a fully executed contract between the SSE Applicant that is a proposed new or existing Generator and a Self Supply LSE that is joining it in requesting the exemption, pursuant to which the SSE Applicant is currently obligated to provide to the Self Supply LSE (or LSEs if more than one Self Supply LSE,) for a minimum of 10 years at the time it requests the Self Supply Exemption, Installed Capacity in an amount greater than or equal to the CRIS MW for which the Self Supply Exemption is requested; or (ii) a fully executed contract between a Self Supply Applicant that is a proposed new or existing UDR project and a Self Supply LSE (or LSEs if more than one Self Supply LSE,) that is joining it in requesting the exemption, pursuant to which the Self Supply LSE(s) will have all rights to the UDRs and the use of the facility, for a minimum of 10 years, in the amount greater than or equal to the CRIS MW for which the Self Supply Exemption is requested.

(c) The Self Supply Applicant's request for a Self Supply Exemption must specify the total quantity of CRIS MW for which it is requesting a Self Supply Exemption, and such quantity shall not exceed the MW of CRIS requested by it in the Class Year or Cluster Study, or the quantity of the transferred CRIS rights at the same location it expects to receive. If there is more than one Self Supply LSE associated with the request for a Self Supply Exemption received from an SSE Applicant then: (i) the request shall identify the quantity of MW associated with each Self Supply LSE, and (ii) the total quantity of MW

associated with the Self Supply LSEs shall not exceed the total MW for which the SSE Applicant requests a Self Supply Exemption.

(d) All Certification and Acknowledgement(s) required by Section 23.4.5.7.14.2 must be received at the same time as the request for a Self Supply Exemption, in accordance with ISO Procedures, along with other data and information requested by the ISO.

23.4.5.7.14.1.2 The lesser of (i) the quantity of CRIS MW for which the Self Supply Exemption was requested and (ii) the quantity determined in accordance with Section 23.4.5.7.14.3 shall be exempt from an Offer Floor if the SSE Applicant is a member of the Class Year or Cluster Study at the time of its completion and the ISO determines that the request satisfies all of the following requirements:

(a) The proposed Generator or UDR project terminus will be, or the existing Generator or UDR project terminus is, electrically located in the same Mitigated Capacity Zone in which the Self-Supply LSE has Projected ICAP Requirements (as such term is defined in Section 23.4.5.7.14.3),

(b) The SSE Applicant and the Developer are not and will not be owned, in whole or in part, by an LSE or an Affiliate of an LSE unless such entity is a Self Supply LSE.

(c) The SSE Applicant provides the completed Certification and Acknowledgement form set forth in Section 23.4.5.7.14.2.1 or 23.4.5.7.14.2.3, as applicable to it and its request for a Self Supply Exemption, and satisfies each requirement stated therein. If the SSE Applicant is not the wholly owned property of the Self Supply LSE(s), or the wholly owned property of an entity that is either wholly owned by the Self Supply LSE(s), or that wholly owns the Self Supply LSE(s), then both the SSE Applicant and the Self Supply LSE(s) provide the applicable completed Certification and Acknowledgement

form set forth in Section 23.4.5.7.14.2 and satisfy each requirement stated therein. The ISO must receive the required completed Certification and Acknowledgement forms, in accordance with ISO Procedures, no later than the deadline by which the SSE Applicant must notify the ISO of its election to enter the Class Year Study or Cluster Study, such date as set forth in Section 25.5.9 of OATT Attachment S or Section 40.5.1 of OATT Attachment HH, or if the Self Supply LSE is an expected recipient of transferred CRIS rights at the same location that will be effective on a date within the Mitigation Study Period for the Class Year or Cluster Study, no later than the Cluster Study Start Date. All other information requested by the ISO must also be timely received.

(d) The ISO determines that the Self Supply LSE satisfies both the Net Short Threshold set forth in Section 23.4.5.7.14.3.1 and the Net Long Threshold set forth in Section 23.4.5.7.14.3.2 for a specified quantity of CRIS MW.

(e) The SSE Applicant certifies that it does not have any contract, agreement, arrangement, or relationship (for purposes of this Section 23.4.5.7.14.1.2(e), and the Certification and Acknowledgment in Section 23.4.5.7.14.2, a "contract") for any material (in whole or in aggregate) payments, concessions, rebates, or subsidies, connected to or contingent on the SSE Applicant's: (i) construction or operation, except as expressly permitted in Subsection (A) or (B) of this Section, or (ii) clearing in the ISO's Installed Capacity market except as expressly permitted in Subsection (B).

(A) An SSE Applicant will not be ineligible for a Self Supply Exemption if it has an executed contract, is associated with a contract, or there is a contract associated with it, that is listed in (I) through (VIII) of this Section that provides for a material payment, concession, rebate or subsidy, and either (i) is not irregular or anomalous, and only

reflects arms-length transactions, or (ii) is consistent with the overall objectives of the Self Supply Exemption.

Listed contracts:

(I) an Interconnection Agreement;

(II) an agreement for the construction or use of interconnection facilities or transmission or distribution facilities, or directly connected joint use transmission or distribution facilities (including contracts required for compliance with Articles VII or 10 of the New York State Public Service Law or orders issued pursuant to Articles VII or 10);

(III) a grant of permission by any department, agency, instrumentality, or political subdivision of New York State to bury, lay, erect or construct wires, cables or other conductors, with the necessary poles, pipes or other fixtures in, on, over or under public property;

(IV) a contract for the sale or lease of real property at or above fair market value as of the date of the agreement was executed, such value demonstrated by an independent appraisal at the time of execution prepared by an accountant or appraiser with specific experience in such valuations;

(V) an easement or license to use real property;

(VI) a contract, with any department, agency, instrumentality, or political subdivision of New York State providing for a payment-in-lieu of taxes (i.e., a “PILOT” agreement) or industrial or commercial siting incentives, such as tax abatements or financing incentives, provided the PILOT agreement or incentives are generally available to industrial or commercial entities;

(VII) a service agreement for natural gas entered into under a tariff accepted by a regulatory body with jurisdiction over that service; or

(VIII) a service agreement entered into under a tariff accepted by a regulatory body with jurisdiction over that service at a regulated rate for electric Station Power, or steam service, excluding an agreement for a rate that is a negotiated rate pursuant to any such regulated electric, or steam tariff.

(B) An SSE Applicant that requests a Self Supply Exemption with only one Self Supply LSE will not be ineligible for a Self Supply Exemption if the contract(s) that otherwise would render it ineligible under any clause of Section 23.4.5.7.14.2 is (or are) with its Self Supply LSE.

(C) Contract Review Opportunity

(i) (1) A proposed new Generator or UDR project or an existing Generator or UDR project for Additional CRIS that is reasonably expected to be eligible to enter the immediately following Class Year or Cluster Study or be the recipient of transferred CRIS rights at the same location on a date within the Mitigation Study Period of such Class Year or Cluster Study, and that in connection with its own Load or for the Load of one or more Self Supply LSE(s) is planning on requesting a Self Supply Exemption; (2) an SSE Applicant that is in a Class Year or Cluster Study that is not completed; or (3) an SSE Applicant that received a Self Supply Exemption, may request that the ISO inform it whether, in the ISO's view, any specific executed contract, unexecuted but substantially developed contract, or any pending request that if approved, granted, or otherwise conferred, would constitute a contract pursuant to Subsection 23.4.5.7.14.1.2 (e)(i) and (e)(ii) would make it ineligible to obtain or (if previously granted) retain a Self Supply Exemption. Any such request must satisfy all of the following requirements:

(a) The SSE Applicant (unless it is for its own Load) must make any such request jointly with any Self Supply LSE(s) with which it has executed or has an unexecuted but substantially developed Long Term Contract. Any such Self Supply LSE(s) must make any such request jointly with the SSE Applicant, or proposed new or existing Generator or UDR project, with which it would seek, or has sought, a Self Supply Exemption.

(b) As part of the submission of the request for a determination pursuant to Subsection (a) of this Section, the SSE Applicant, or proposed new or existing Generator or UDR project, and any relevant Self Supply LSE(s) as applicable, must provide the ISO with all information regarding the contract or pending request regarding which it is requesting the ISO's view, and if the request is made jointly with a Self Supply LSE, the executed or unexecuted and substantially developed Long Term Contract that would form the basis of a Self Supply Exemption Request, including copies of original documentation. In addition and at the time of the submission of the request, the SSE Applicant, or proposed new or existing Generator or UDR project, and any relevant Self Supply LSE shall also provide any other information identified by the ISO in accordance with ISO Procedures. They also must timely provide any further information that is requested by the ISO.

(c) Such requests can only be submitted to the ISO on or after the date established by the ISO in accordance with ISO Procedures, such date to be at least 60 days prior to the date that the ISO anticipates will be the deadline by which facilities must notify the ISO of their election to enter a Class Year or Cluster Study as set forth

in Section 25.5.9 of OATT Attachment S or Section 40.5.1 of OATT Attachment HH, as applicable.

(ii) Provided that the ISO has timely received all of the information it needs to make a determination, the ISO shall state its view in response to such requests within 60 days.

(iii) When evaluating any such request, the ISO shall consult with the 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 30.4.6.2.13 of Attachment O to this Services Tariff.)

23.4.5.7.14.2 Certifications and Acknowledgements

23.4.5.7.14.2.1 An SSE Applicant that is not the wholly owned property of the Self Supply LSE(s), or the wholly owned property of an entity that is either wholly owned by the Self Supply LSE(s), or that wholly owns the Self Supply LSE(s), and that is requesting a Self Supply Exemption shall submit the following completed Certification and Acknowledgment form. The submission must be received by the ISO by the deadline pursuant to Section 23.4.5.7.14.1.2(c), and thereafter upon the request of the ISO, in accordance with ISO Procedures. The Self Supply Applicant shall be legally bound by the Certification and Acknowledgement form which must be executed by a duly authorized officer:

CERTIFICATION AND ACKNOWLEDGMENT

I [NAME & TITLE] hereby certify on behalf of myself, [NAME OF PROJECT], and [NAME OF INTERCONNECTION CUSTOMER] that each of the following statements is true and correct:

1. I am an officer whose responsibilities include the development of the [EXAMINED FACILITY, NCZ EXAMINED PROJECT or ADDITIONAL CRIS MW], New York Independent System Operator, Inc.'s ("NYISO") Queue Position Number [INSERT NUMBER] (the "Project").

2. I am duly authorized to make representations concerning the Project, including each of the certifications and acknowledgements that I have made in this document.

3. I hereby [REQUEST ON BEHALF OF] the Interconnection Customer, a Self Supply Exemption for [MW REQUESTED FOR THE SELF SUPPLY EXEMPTION] for the Project in connection with [LOAD SERVING ENTITY THAT IS THE SELF SUPPLY LSE].

4. I have reviewed and I understand the requirements established under the NYISO Market Administration and Control Area Services Tariff ("Services Tariff") related to a "Self Supply Exemption" pursuant to Section 23.4.5.7.14.

5. I have personal knowledge of the facts and circumstances supporting the Project's request and eligibility for a Self Supply Exemption as of the date of this Certification and Acknowledgment, including all data and other information submitted by the Project to the NYISO.

6. [NAME OF INTERCONNECTION CUSTOMER] is not owned in whole or in part by, and is not an Affiliate (as Affiliate is defined in Section 2.1 of the Services Tariff) of, a Load Serving Entity [OTHER THAN THE LOAD SERVING ENTITY THAT IS THE SELF SUPPLY LSE].

7. [NAME OF PROJECT] has a Long Term Contract (as such term is defined in Services Tariff Section 23.4.5.7.14.1.1 (b)(1)) with the Self Supply LSE[s], that is [are] the subject of the request for a Self Supply Exemption.

8. To the best of my knowledge and having conducted due diligence that is current as of the date of this Certification there is no contract, arrangement, arrangement, or relationship (for purposes of Section 23.4.5.7.14. 2(e) of the Services Tariff, and this Certification and Acknowledgment, a "contract") for any material (in whole or in aggregate) payments, concessions, rebates or subsidies connected to or contingent on the [PROJECT's]: (i) construction or operation, except as expressly permitted in Subsection (A) or (B) of Section 23.4.5.7.14.1. 2(e) of the Services Tariff, or (ii) clearing in the NYISO's Installed Capacity market except as expressly permitted in Subsection (B) of Section 23.4.5.7.14. 1.2(e).

9. I have listed in Schedule 1 to this Certification all contracts that involve payments, concessions, rebates, or subsidies connected to or contingent upon the [PROJECT'S] construction or operation that are not material or that are otherwise expressly permissible under Subsection (A) or (B) of Section 23.4.5.7.14.1.2(e).

10. The Project shall provide any information or cooperation requested by the NYISO in connection with the Project's request for a Self Supply Exemption.

I hereby acknowledge on behalf of myself, [INSERT NAME OF PROJECT], and [NAME OF INTERCONNECTION CUSTOMER] that:

a. The submission of false, misleading, or inaccurate information, or the failure to submit information requested by the NYISO related to the Project's request for a Self Supply Exemption, including but not limited to information contained or submitted in this Certification and Acknowledgement on behalf of the Project, shall constitute a violation of Section 4.1.7 of the Services Tariff, and subject to the Commission's review, a violation of the Commission's regulations and Section 316A of the Federal Power Act.

b. If the Project submits false, misleading, or inaccurate information, or fails to submit requested information to the NYISO, including but not limited to information contained or submitted in this Certification and Acknowledgement on behalf of the Project, it shall cease to be eligible for a Self Supply Exemption and, if the Project has already received a Self Supply Exemption, that exemption shall be subject to revocation by the NYISO or the Commission after which the Project shall be subject to an Offer Floor set at the Mitigation Net CONE Offer Floor (such value calculated based on the date it first Offers UCAP, in accordance with Section 23.4.5.7.3.7, and adjusted annually in accordance with Section 23.4.5.7 of the Services Tariff,) starting with the next following deadline for Unforced Capacity certification prior to an ICAP Spot Market Auction subsequent to the date of revocation (such date in accordance with ISO Procedures) pursuant to Section 23.4.5.7.9.5 of the Services Tariff.

c. If the Project submits false, misleading, or inaccurate information, or fails to submit requested information to the NYISO, including but not limited to information contained or submitted in the Certification and Acknowledgement on behalf of the Project, it may be subject to civil penalties that may be imposed by the Commission for violations of Section 4.1.7 of Services Tariff, the Commission's rules, and/or Section 316A of the Federal Power Act.

_____

[PRINT NAME]
[DATE]

Subscribed and sworn to before me

this [ ] day of [MONTH] [YEAR].

_____

Notary Public

My commission expires:_____

23.4.5.7.14.2.2 A Self Supply LSE that has a Long Term Contract (as such term is defined in Section 23.4.5.14.1(b)(1)) with an SSE Applicant shall submit to the ISO the following completed Certification and Acknowledgement Form as part of the SSE Applicant's request for a Self Supply Exemption and thereafter upon the request of the ISO, in accordance with ISO Procedures. The Self Supply LSE shall be legally bound by the completed Certification and Acknowledgement form which must be executed by a duly authorized officer:

CERTIFICATION AND ACKNOWLEDGMENT

I [NAME & TITLE] hereby certify on behalf of myself and [NAME OF SELF SUPPLY LSE] (the "LSE") that each of the following statements is true and correct:

1. I am an officer whose responsibilities include overseeing the capacity supply portfolio and obligations, and addressing Load requirements of the [LSE], and LSE's Long Term Contract (as such term is defined in Services Tariff Section 23.4.5.7.14.1.1 (b)(1))with [EXAMINED FACILITY, NCZ EXAMINED PROJECT, or ADDITIONAL CRIS MW], New York Independent System Operator, Inc.'s ("NYISO") Queue Position Number [INSERT NUMBER] (the "Project").

2. I am duly authorized to make representations concerning the capacity supply portfolio, and obligations, Load requirements of [the LSE], and LSE's Long Term Contract with the Project (the "Subject Long Term Contract"), including each of the certifications and acknowledgements that I have made in this document.

3. I hereby [REQUEST ON BEHALF OF] the LSE, a Self Supply Exemption for [MW REQUESTED FOR THE SELF SUPPLY EXEMPTION] for the Project associated with the Subject Long Term Contract.

4. I have reviewed and I understand the requirements established under the NYISO Market Administration and Control Area Services Tariff ("Services Tariff") related to a "Self Supply Exemption" pursuant to Section 23.4.5.7.14.

5. I have personal knowledge of the facts and circumstances supporting the Subject Long Term Contract and LSE's Load Obligations and supply obligations related to the Project's request and eligibility for a Self Supply Exemption as of the date of this Certification and Acknowledgment, including all data and other information submitted by LSE to the NYISO.

6. The LSE is a Self Supply LSE [INSERT SUBSECTION OF DEFINITION BY WHICH THE LSE MEETS THE REQUIREMENTS OF THAT TERM] of that term.

7. [NAME OF INTERCONNECTION CUSTOMER] [is // is not] owned in part by, and [is // is not] an Affiliate (as Affiliate is defined in Section 2.1 of the Services Tariff) of, LSE. Appendix A to this Certification and Acknowledgement fully and completely sets forth and describes the organizational relationship between or among LSE, Interconnection Customer and the Project, or any Affiliate of the foregoing entities in relation to the project; and any ownership or investment interest of LSE, Interconnection Customer, and the Project, in either of the other entities, or any of the Affiliates thereof in relation to the Project.

8. [NAME OF PROJECT] and LSE are parties to the Subject Long Term Contract.

9. To the best of my knowledge and having conducted due diligence that is current as of the date of this Certification there are no arrangements for any payments or subsidies, that are directly or indirectly tied to the Unforced Capacity from the Project clearing in the NYISO's Installed Capacity market other than those between the [NAME OF DEVELOPER],[PROJECT] and [SELF SUPPLY LSE] that is provided to the ISO with this Certification and Acknowledgement [and other than agreements between [NAME OF INTERCONNECTION CUSTOMER], [PROJECT] and [NAME OF OTHER SELF SUPPLY LSE(S) ASSOCIATED WITH THE SELF SUPPLY APPLICANT'S REQUEST FOR A SELF SUPPLY EXEMPTION].

10. I have listed in Schedule 1 to this Certification all contracts that involve payments, concessions, rebates, or subsidies connected to or contingent upon the [PROJECT'S] construction or operation that are not material or that are otherwise expressly permissible under Subsection (A) or (B) of Section 23.4.5.7.14.1.2(e).

11. LSE shall provide any information or cooperation requested by the NYISO in connection with the LSE and the Project's request for a Self Supply Exemption.

I hereby acknowledge on behalf of myself and LSE that:

a. The submission of false, misleading, or inaccurate information, or the failure to submit information requested by the NYISO related to the LSE's and the Project's request for a Self Supply Exemption, including but not limited to information contained or submitted in this Certification and Acknowledgement on behalf of the Project, shall constitute a violation of Section 4.1.7 of the Services Tariff, and subject to the Commission's review, a violation of the Commission's regulations and Section 316A of the Federal Power Act.

b. If the LSE or the Project submits false, misleading, or inaccurate information, or fails to submit requested information to the NYISO, including but not limited to information contained or submitted in this Certification and Acknowledgement on behalf of the LSE, the Project shall cease to be eligible for a Self Supply Exemption in respect of Subject Long Term Contract and, if the Project has already received a Self Supply Exemption, that exemption shall be subject to revocation by the NYISO or the Commission after which the Project shall be subject to an Offer Floor set at the Mitigation Net CONE Offer Floor (such value calculated based on the date it first Offers UCAP, in accordance with Section 23.4.5.7.3.7, and adjusted annually in accordance with Section 23.4.5.7 of the Services Tariff,) starting with the next following deadline for Unforced Capacity certification prior to an ICAP Spot Market Auction subsequent to the date of revocation (such date in accordance with ISO Procedures) pursuant to Section 23.4.5.7.9.5 of the Services Tariff.

c. If the LSE submits false, misleading, or inaccurate information, or fails to submit requested information to the NYISO, including but not limited to information contained or submitted in the Certification and Acknowledgement on behalf of the Project, it may be subject to civil penalties that may be imposed by the Commission for violations of Section 4.1.7 of Services Tariff, the Commission's rules, and/or Section 316A of the Federal Power Act.

_____

[PRINT NAME]
[DATE]

Subscribed and sworn to before me
this [ ] day of [MONTH] [YEAR].

_____

Notary Public

My commission expires:_____

23.4.5.7.14.2.3 An SSE Applicant that is the wholly owned property of the Self Supply LSE, or the wholly owned property of an entity that is either wholly

owned by the Self Supply LSE, or that wholly owns the Self Supply LSE, and that is requesting a Self Supply Exemption shall submit the following completed Certification and Acknowledgment Form. The submission must be received by the ISO by the deadline pursuant to Section 23.4.5.7.14.1.2(c), and thereafter upon the request of the ISO, in accordance with ISO Procedures. The Self Supply Applicant shall be legally bound by the following Certification and Acknowledgement form which must be executed by a duly authorized officer:

CERTIFICATION AND ACKNOWLEDGMENT

I [NAME & TITLE] hereby certify on behalf of myself, [NAME OF PROJECT], and [NAME OF INTERCONNECTION CUSTOMER/LSE] that each of the following statements is true and correct:

1. I am an officer whose responsibilities include; (i) the development of the [EXAMINED FACILITY, NCZ EXAMINED PROJECT, or ADDITIONAL CRIS MW], New York Independent System Operator, Inc.'s ("NYISO") Queue Position Number [INSERT NUMBER] (the "Project"); and (ii) overseeing the capacity supply portfolio and obligations, and addressing Load Obligations of the Self Supply LSE and its obligations to serve retail customers.

2. I am duly authorized to make representations concerning the Project and the capacity supply portfolio, and obligations, Load requirements of [the INTERCONNECTION CUSOTMER/LSE], including, if applicable the Long Term Contract between the Project and any entity performing the Self Supply LSE function (the "Subject Long Term Contract"), and also including each of the certifications and acknowledgements that I have made in this document.

3. I hereby [REQUEST ON BEHALF OF] the [INTERCONNECTION CUSTOMER/LSE], a Self Supply Exemption for [MW REQUESTED FOR THE SELF SUPPLY EXEMPTION] for the Project associated with [INTERCONNECTION CUSTOMER/LSE'S] self supply arrangements, including, if applicable, any Subject Long Term Contract.

4. I have reviewed and I understand the requirements established under the NYISO Market Administration and Control Area Services Tariff ("Services Tariff") related to a "Self Supply Exemption" pursuant to Section 23.4.5.7.14.

5. I have personal knowledge of the facts and circumstances supporting: (i) the Project's request and eligibility for a Self Supply Exemption; and (ii) the Load Obligations and supply obligations related to the Project's request and eligibility for a Self Supply Exemption, as of the date of this Certification and Acknowledgment, including all data and other information submitted by the Project and by [INTERCONNECTION CUSTOMER/LSE] to the NYISO.

6. The LSE is a Self Supply LSE pursuant to Section [INSERT SUBSECTION OF DEFINITION BY WHICH THE LSE MEETS THE REQUIREMENTS OF THAT TERM] of that term.

7. [NAME OF INTERCONNECTION CUSTOMER/LSE] is not owned in whole or in part by, and is not an Affiliate (as Affiliate is defined in Section 2.1 of the Services Tariff) of, any other Load Serving Entity. Appendix A to this Certification and Acknowledgement fully and completely sets forth and describes the organizational relationship between [INTERCONNECTION CUSTOMER/LSE's] Self Supply LSE and Interconnection Customer functions or affiliates and the Project.

8. To the best of my knowledge and having conducted due diligence that is current as of the date of this Certification there is not any contract, agreement, arrangement, or relationship (for purposes of Section 23.4.5.7.14.1.2(e), and this Certification and Acknowledgment, a "contract") for any material (in whole or in aggregate) payments, concessions, rebates, or subsidies, connected to or contingent on the [PROJECT's]: (i) construction or operation, except as expressly permitted in Subsection (A) or (B) of Section 23.4.5.7.14.1.2(e) of the Services Tariff, or (ii) clearing in the NYISO's ICAP market except as expressly permitted in Subsection (B) of Section 23.4.5.7.14.1.2(e).

9. I have listed in Schedule 1 to this Certification all contracts that involve payments, concessions, rebates, or subsidies connected to or contingent upon the [PROJECT'S] construction or operation that are not material or that are otherwise expressly permissible under Subsection (A) or (B) of Section 23.4.5.7.14.1.2(e).

10. The Project and [INTERCONNECTION CUSTOMER/LSE] shall provide any information or cooperation requested by the NYISO in connection with the Project's request for a Self Supply Exemption.

I hereby acknowledge on behalf of myself, [INSERT NAME OF PROJECT], and [NAME OF INTERCONNECTION CUSTOMER/LSE] that:

a. The submission of false, misleading, or inaccurate information, or the failure to submit information requested by the NYISO related to the Project's and [INTERCONNECTION CUSTOMER/LSE's] request for a Self Supply Exemption, including but not limited to information contained or submitted in this Certification and Acknowledgement on behalf of the Project, shall constitute a violation of Section 4.1.7 of the Services Tariff, and subject to the Commission's review, a violation of the Commission's regulations and Section 316A of the Federal Power Act.

b. If the INTERCONNECTION CUSTOMER/LSE or the Project submits false, misleading, or inaccurate information, or fails to submit requested information to the NYISO, including but not limited to information contained or submitted in this Certification and Acknowledgement on behalf of the Project, it shall cease to be eligible for a Self Supply Exemption and, if the Project has already received a Self Supply Exemption, that exemption shall be subject to revocation by the NYISO or the Commission after which the Project shall be subject to an Offer Floor set at the Mitigation Net CONE Offer Floor (such value calculated based on the date it first Offers UCAP, in accordance with Section 23.4.5.7.3.7, and adjusted annually in accordance with Section 23.4.5.7 of the Services Tariff,) starting with the next following deadline for Unforced Capacity certification prior to an ICAP Spot Market Auction subsequent to the date of revocation (such date in accordance with ISO Procedures) pursuant to Section 23.4.5.7.9.5 of the Services Tariff.

c. If the INTERCONNECTION CUSTOMER/LSE or the Project submits false, misleading, or inaccurate information, or fails to submit requested information to the NYISO, including but not limited to information contained or submitted in the Certification and Acknowledgement on behalf of the Project, it may be subject to civil penalties that may be imposed by the Commission for violations of Section 4.1.7 of Services Tariff, the Commission's rules, and/or Section 316A of the Federal Power Act.

_____

[PRINT NAME]
[DATE]

Subscribed and sworn to before me
this [ ] day of [MONTH] [YEAR].

_____

Notary Public

My commission expires: _____

23.4.5.7.14.3 Net Short Threshold and Net Long Threshold

For the purposes of Section 23.4.5.7.14.3, "SSE Evaluated ICAP" shall mean the quantity of MW of CRIS for which a Self Supply Exemption is requested by an individual Self Supply LSE (or by an SSE Applicant in respect of its own Load) in accordance with Section 23.4.5.7.14.1.1(c), unless reduced as follows: If (i) following a notice that an Additional SDU Study(ies) will be conducted in accordance with Section 25.7.7.1 or 40.13.7,1 of the OATT, an SSE Applicant elects to keep its CRIS request but with no System Deliverability Upgrade identified to make the project fully deliverable (as provided for in Section 25.5.10.1(1) or 40.14.1(1)),) and (ii) the total quantity of MW of CRIS for which the Self Supply Exemption is requested exceeds the total amount of Deliverable MW, as specified in the next Class Year Interconnection Facilities Study or Cluster Study report, the ISO shall reduce the total quantity of MW of CRIS for which a Self Supply Exemption is requested to the total amount of Deliverable MW identified in such Class Year Interconnection Facilities Study or Cluster Study report. If there is more than one LSE associated with the SSE Applicant, the ISO shall reduce the quantity of MW of CRIS for each Self Supply LSE by the ratio of Deliverable MW to the total MW of CRIS for which Self Supply exemptions were initially requested.

The ISO shall compute the Net Short Threshold and Net Long Threshold, and determine whether each is satisfied, based on its computation of each of the values specified in this Section. If there is more than one Self Supply LSE associated with the SSE Applicant's request for a Self Supply Exemption, the MW associated with each Self Supply LSE shall be considered separately.

If the Self Supply LSE or its Affiliates are associated with more than one request for a Self Supply Exemption in the Class Year or Cluster Study (including any associated with a

transfer of CRIS at the same location,) and the Self Supply LSE and its Affiliates satisfy the Net Long Threshold in a non-zero amount that is greater than the "Cumulative Affiliated Quantity" (as defined in Section 23.4.5.7.14.3,) then remaining in the Class Year or Cluster Study, the ISO shall reduce the quantity of MW for which they are eligible to receive a Self Supply Exemption by the ratio of (a) the quantity of MW by which the Self Supply LSE and its Affiliates satisfy the Net Long Threshold, to (b) the Cumulative Affiliated Quantity associated with SSE Applicant(s) then remaining in the Class Year or Cluster Study or associated with a transfer of CRIS at the same location (provided the transferee does not notify the ISO, on or before the date the Class Year or Cluster Study is completed, that it no longer expects to be the recipient of the transferred CRIS.)

For the purposes of Section 23.4.5.7.14.3, "Projected ICAP Requirements" is the amount of ICAP MW reasonably projected by the ISO that reflects the expected obligations of the Self Supply LSE, and all its Affiliates, to satisfy the ICAP Requirements of its long term customers. This amount will equal the sum of the total amounts projected by the ISO that will be required to be purchased in each Locality and the NYCA for its long term customers. Such projection shall be based on the Self Supply LSE's and all its Affiliates' share(s) of the Locational Minimum Unforced Capacity Requirements and the NYCA Minimum Unforced Capacity Requirement, as applicable and in accordance with ISO Procedures, over the ten most recently completed Capability Years preceding the Cluster Study Start Date and any incremental long term customers that have entered contracts with the Self Supply LSE or its Affiliates with a term of 10 years or more prior to the Class Year Study's or Cluster Study's Initial Decision Round. Such projection shall also reflect that ICAP MW purchased in a Locality may be used to meet capacity requirements for each Locality in which they are contained, as well as for the NYCA.

When calculating the Self Supply LSE's and all its Affiliates' Projected ICAP Requirements, each of their shares of the Locational Minimum Unforced Capacity Requirements and the NYCA Minimum Unforced Capacity Requirement over these ten Capability Years shall be translated to their ICAP MW equivalent(s) using the derating factor that was applied to translate the Installed Capacity Requirement into the Unforced Capacity Requirement in the same Capability Period and Locality, or the NYCA if applicable, in which the purchase was made.

For the purposes of Section 23.4.5.7.14.3, "Excess Award Percentage" is the reasonably projected amount of excess capacity that the Self Supply LSE and all its Affiliates will be required to purchase in each Locality, and the NYCA, expressed as a percentage of its "Projected ICAP Requirements", Such projection shall be based on the total excess UCAP MW awarded in each ICAP Spot Market Auction, divided by the Locational Minimum Unforced Capacity Requirement, or the NYCA Minimum Unforced Capacity Requirement, for the same Capability Period and Locality (or the NYCA) in which the award was made, over the three most recently completed Capability Years preceding the Cluster Study Process Start Date.

For the purposes of Section 23.4.5.7.14.3, "Capacity Obligations without Entry", calculated for each Locality and the NYCA, is the product of (a) Projected ICAP Requirements and (b) one plus the Excess Award Percentage.

For the purposes of Section 23.4.5.7.14.3, "Capacity Obligations with Entry", calculated for each Locality and the NYCA, is the product of (a) Projected ICAP Requirements and (b) one plus the Excess Award Percentage, adjusted to reflect the projected increase in excess that the Self Supply LSE would be obligated to purchase as a result of the entry of the SSE Applicant.

For the purposes of Section 23.4.5.7.14.3, "Self Supply Capacity" for a given Locality (or the NYCA,) is (a) the full amount of ICAP MW associated with each Generator or UDR project that the Self Supply LSE or any of its Affiliates own directly or indirectly, in at least a 50.01% interest (in the aggregate) as of the Cluster Study Process Start Date, or have the power to direct the management or policies of, excluding any whose CRIS MW are projected by the ISO to be expired on or before the date that marks the end of Mitigation Study Period, based on a demonstration by the Self Supply LSE, and (b) the ICAP MW that the Self Supply LSE and all its Affiliates are reasonably projected by the ISO to receive, including ICAP MW which they have a call option to receive, either by way of ownership or under "Existing Long Term Commitments" in that Locality (or the NYCA), and that are associated with a Generator or UDR project that the Self Supply LSE or any of its Affiliates do not own directly or indirectly, at least a 50.01% interest (in the aggregate) as of the Cluster Study Process Start Date, and that they do not have the power to direct the management or policies of, excluding those that are associated with any Generator or UDR project identified in Excluded Capacity pursuant to Section 23.4.5.7.15. For purposes of Self Supply Capacity, "Existing Long Term Commitments" is the amount of Capacity that the Self Supply LSE or any of its Affiliates are projected by the ISO to receive, which shall include ICAP which they have a call option to receive, under a written agreement (whether stated in ICAP or otherwise,) with a minimum term of ten years obligation remaining thereon on the Cluster Study Process Start Date. When calculating the term and remaining term of a written agreement for the purposes of this section, the ISO, using its independent judgment and at its sole discretion, will determine whether to reflect in its calculation any potential extension to the current term of a written agreement that may reasonably result from renewal provisions.

For the purposes of Section 23.4.5.7.14.3, "Additional Self Supply Capacity," for a given Locality (or the NYCA,) is the ICAP MW of a Generator or UDR project that were granted a Self Supply Exemption at the time of the completed Class Year or Cluster Study based on the Self Supply LSE or any of its Affiliates' being a Self Supply LSE for such Generator or UDR project, in the 10 year period immediately preceding the Class Year Start Date of the Class Year, or Cluster Study Process Start Date of the Cluster Study, as applicable, in that Locality (or the NYCA), excluding: (i) any ICAP MW that are included in Self Supply Capacity, (ii) any ICAP MW associated with a Generator or UDR project that the Self Supply LSE and any of its Affiliates own directly or indirectly, at least a 50.01% interest(in the aggregate) as of the Cluster Study Process Start Date, or have the power to direct the management or policies of, and that the CRIS of which is projected by the ISO to be expired on or before the date that marks the end of Mitigation Study Period, based on a demonstration by the Self Supply LSE; and (iii) any ICAP MW of a Generator or UDR project that neither the Self Supply LSE nor any of its Affiliates own directly or indirectly, at least a 50.01% interest (in the aggregate) as of the Cluster Study Process Start Date, or have the power to direct the management or policies of, and that is a Generator or UDR project identified in Excluded Capacity pursuant to Section 23.4.5.7.15.

23.4.5.7.14.3.1 Net Short Threshold

The Net Short Threshold will be satisfied for the "SSE Evaluated ICAP" if the ISO determines that, summed over all Localities and the NYCA, the Self Supply LSE's and all of its Affiliates' "Total Capacity Costs without Entry" are expected to be less than the Self Supply LSE's and all of its Affiliates' "Total Capacity Costs with Entry" when accounting for the nested structure of the Self Supply LSE's ICAP Requirements.

23.4.5.7.14.3.1.1 The ISO will calculate the estimated "Total Capacity Costs without Entry" as the sum over all Localities, and the NYCA, of the product of (a) the "ICAP Spot Auction Price without Entry" and (b) the "Capacity Exposed to Market Prices without Entry".

(a) "ICAP Spot Market Auction Price without Entry" shall be based on the ICAP Spot Market Auction prices for each Locality and the NYCA, averaged over the three most recently completed Capability Years preceding the Cluster Study Process Start Date.

(b) "Capacity Exposed to Market Prices without Entry" is calculated for each Locality and the NYCA as:

"Capacity Obligations without Entry" for each Locality and the NYCA, translated from ICAP MW into UCAP MW using the average derating factor for each Locality and the NYCA corresponding to the ICAP Spot Market Auctions used to determine the ICAP Spot Market Auction Price without Entry;

minus

"Self Supply Capacity" for each Locality and the NYCA, translated from ICAP MW into UCAP MW using a derating factor, as determined by the ISO, that is reasonably anticipated to be associated with ICAP Suppliers included in this Self Supply Capacity;

minus

"Additional Self Supply Capacity" for each Locality and the NYCA, translated from ICAP MW into UCAP MW using a derating factor, as determined by the

ISO, that is reasonably anticipated to be associated with ICAP Suppliers included in this Additional Self Supply Capacity;

minus

"Previously Included Capacity Exposed to Market Prices without Entry," which shall be determined as follows: When calculating "Capacity Exposed to Market Prices Without Entry" for the New York City or Long Island Localities, "Previously Included Capacity Exposed to Market Prices without Entry" shall be zero. When calculating "Capacity Exposed to Market Prices without Entry" for the G-J Locality, "Previously Included Capacity Exposed to Market Prices without Entry" shall be set equal to "Capacity Exposed to Market Prices without Entry" calculated for the New York City Locality. When calculating "Capacity Exposed to Market Prices without Entry" for the NYCA, "Previously Included Capacity Exposed to Market Prices without Entry" shall be set equal to the sum of "Capacity Exposed to Market Prices without Entry" calculated for the G-J, New York City, and Long Island Localities.

23.4.5.7.14.3.1.2 The ISO will calculate "Total Capacity Costs with Entry" as the sum of "Proportional Entry Costs" and the sum over all Localities, and the NYCA, of the product of (a) "ICAP Spot Market Auction Price With Entry" and (b) "Capacity Exposed to Market Prices With Entry".

"Proportional Entry Costs" is the percentage of the Unit Net CONE (expressed in dollars) of the SSE Applicant (calculated in accordance with Section 23.4.5.7.3 if an Examined Facility, or in accordance with Section 23.4.5.7.2.1 if an NCZ Examined Project, or in accordance with Section 23.4.5.7.6.1 if Additional CRIS

MW) that is equal to the SSE Evaluated ICAP divided by the total MW of CRIS requested by the SSE Applicant in the Class Year or Cluster Study.

(a) The "ICAP Spot Market Auction Price with Entry" shall be based on the ICAP Spot Market Auction prices calculated for each Locality and the NYCA, averaged over the three most recently completed Capability Years preceding the Cluster Study Process Start Date, and adjusted to reflect the entry of the SSE Applicant.

(b) the "Capacity Exposed to Market Prices with Entry" is calculated for each Locality and the NYCA as:

"Capacity Obligations with Entry" for each Locality and the NYCA, translated from ICAP MW into UCAP MW using the average derating factor for each Locality and the NYCA corresponding to the ICAP Spot Market Auctions used to determine the ICAP Spot Market Auction Price with Entry;

Minus

"Self Supply Capacity" for each Locality and the NYCA, translated from ICAP MW into UCAP MW using a derating factor, as determined by the ISO, that is reasonably anticipated to be associated with ICAP Suppliers included in this Self Supply Capacity;

minus

"Additional Self Supply Capacity" for each Locality and the NYCA, translated from ICAP MW into UCAP MW using a derating factor, as determined by the ISO, that is reasonably anticipated to be associated with ICAP Suppliers included in this Additional Self Supply Capacity;

minus

"SSE Evaluated ICAP", translated from ICAP MW into UCAP MW using a derating factor, as determined by the ISO that is reasonably anticipated to be associated with the SSE Applicant;

minus

"Previously Included Capacity Exposed to Market Prices with Entry," which shall be determined as follows: When calculating "Capacity Exposed to Market Prices With Entry" for the New York City or Long Island Localities, "Previously Included Capacity Exposed to Market Prices with Entry" shall be zero. When calculating "Capacity Exposed to Market Prices with Entry" for the G-J Locality, "Previously Included Capacity Exposed to Market Prices with Entry" shall be set equal to "Capacity Exposed to Market Prices with Entry" calculated for the New York City Locality. When calculating "Capacity Exposed to Market Prices with Entry" for the NYCA, "Previously Included Capacity Exposed to Market Prices with Entry" shall be set equal to the sum of "Capacity Exposed to Market Prices with Entry" calculated for the G-J, New York City, and Long Island Localities.

23.4.5.7.14.3.2 Net Long Threshold

If the Self Supply LSE and any of its Affiliates are associated with more than one Self Supply Exemption Request in the Class Year or Cluster Study, the Net Long Threshold determination will be made based on the sum of the Self Supply LSE's and all of its Affiliates' SSE Evaluated ICAP ("Cumulative Affiliated Quantity") prior to the Initial Decision Round. The ISO shall recalculate the Cumulative Affiliated Quantity prior to the ISO's issuance of a Revised Project Cost Allocation Subsequent Decision Round if any SSE Applicant with which it is associated is no longer in the Class Year or Cluster Study.

For each Mitigated Capacity Zone containing the location of the SSE Applicant, the ISO will determine the largest amount of SSE Evaluated ICAP MW that is (a) less than or equal to the sum of the Self Supply LSE's and all of its Affiliates' "SSE Evaluated ICAP" and (b) for which the Self Supply LSE's and all of its Affiliates' "Total Self Supply Capacity" is less than or equal to the "Future Capacity Obligation." The Net Long Threshold will be satisfied for the smallest of these determined amounts of SSE Evaluated ICAP MW, and will be considered not satisfied if the smallest of these amounts is less than or equal to zero.

(i) The "Total Self Supply Capacity" is the sum, in each Mitigated Capacity Zone, of ICAP MW of (A) Self Supply Capacity, (B) Additional Self-Supply Capacity, and (C) the cumulative quantity of the Self Supply LSE's and all of its Affiliates' SSE Evaluated ICAP.

(ii) the "Future Capacity Obligation" is the product of (A) ICAP MW of Capacity Obligations without Entry, and (B) the higher of (x) one plus the "10 year growth rate of peak demand" and (y) one plus one percent. The "10 year growth rate of peak demand" shall be determined based on the longest available NYSO Baseline forecast of non-coincident peak demand for the corresponding Mitigated Capacity Zone found in the "Baseline Forecast of Non-Coincident Peak Demand" table, or its successor in the most current Gold Book, published by the Cluster Study Process Start Date of the Class Year, for each Mitigated Capacity Zone.

23.4.5.7.14.4 Timing of Determinations

23.4.5.7.14.4.1 Determinations.

(a) Prior to the Initial Decision Round, the ISO shall determine whether all or a portion of the MW specified in the request for a Self Supply Exemption is eligible

for a Self Supply Exemption in accordance with Section 23.4.5.7.14.1.2. If the ISO determines that all or a portion of the CRIS MW for which a Self Supply Exemption was requested is not eligible for a Self Supply Exemption, the ISO shall make a determination in accordance with Section 23.4.5.7.3.2 prior to the commencement of the Initial Decision Round, and prior to the ISO's issuance of a Revised Project Cost Allocation. When evaluating eligibility for a Self Supply Exemption, the ISO shall consult with the 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 30.4.6.2.13 of Attachment O to this Services Tariff.

(b) Determinations made pursuant to Section 23.4.5.7.14.4 shall be provided to the SSE Applicant concurrent with the issuance of determinations in accordance with Section 23.4.5.7.3.3, and to an NCZ Examined Project at the time of the ISO's determination pursuant to Section 23.4.5.7.2.1.

(c) The ISO shall post on its web site and concurrently notify the Self Supply LSE of the ISO's determination of exempt, and if exempt the quantity of MW exempted, or non-exempt, from an Offer Floor as soon as the determination is final. Concurrent with the ISO's posting, the Market Monitoring Unit shall publish a report on the ISO's determination, as further specified in Sections 30.4.6.2.13 of Attachment O to this Services Tariff.

23.4.5.7.14.5 Revocation of a Self Supply Exemption

(a) If, at the time prior to the SSE Applicant first producing or transmitting, Energy it or the Self Supply LSE no longer satisfies the requirements of Section

23.4.5.7.14.1(b) or no longer meets the requirements of the Acknowledgement and Certification, the SSE Applicant and the Self Supply LSE shall notify each other and the ISO in writing within 3 business days of the event or basis for the failure to meet the requirements for a Self Supply Exemption. Within 10 business days of its receipt of this notification, the ISO shall provide written notice of its intent to revoke the Self Supply Exemption that specifies its findings. The ISO will provide an opportunity for the SSE Applicant of Self Supply LSE to schedule a joint meeting with the ISO within 20 business days from the date of its notice of intent to revoke the Self Supply Exemption. The purpose of the meeting will be to allow the submittal of additional documentation and other facts that could rebut the findings of the ISO that were identified in its notice of intent to revoke the Self Supply Exemption. The ISO shall determine within 10 business days of this joint meeting whether the revocation of the Self Supply Exemption shall be finalized and then shall post on its website its determination to revoke the Self Supply Exemption. If the ISO revokes the Self Supply Exemption, the Generator will be subject to the Mitigation Net CONE Offer Floor (such value calculated based on the date it first offers UCAP, in accordance with Section 23.4.5.7.3.7, and adjusted annually in accordance with Section 23.4.5.7 of this Services Tariff.)

(b) The failure to provide the ISO written notice in accordance with Section 23.4.5.7.14.5(a) shall constitute a violation of the Services Tariff. Such violation shall be reported by the ISO to the Market Monitoring Unit and to the Commission’s Office of Enforcement (or any successor to its responsibilities.)

(c) Where the ISO reasonably believes that a request for a Self Supply Exemption was granted based on (i) false, misleading, or inaccurate information, or (ii) the Self Supply LSE's inclusion within "Self Supply Capacity" (as that term is used in Section 23.4.5.7.14.3) of a Generator or UDR project's capacity that was identified by the Self Supply LSE whose CRIS was projected to expire before the end of the Mitigation Study Period but has not expired on or before the date that marked the end of the Mitigation Study Period, the ISO shall notify the SSE Applicant or the Owner/Operator of the Generator or UDR, and the Self Supply LSE that the Self Supply Exemption may be revoked in writing. The written notice shall provide to the Self Supply Applicant, or the Owner/Operator of the Generator or UDR, and the Self Supply LSE an opportunity to submit documentation to the ISO and meet jointly with the ISO to rebut the ISO's findings within 30 days from the date of the ISO's written notice. The ISO shall determine within 10 business days of this meeting whether the revocation of the Self Supply Exemption shall be finalized and post on its website its determination to revoke the Self Supply Exemption. Where the ISO revokes the Self Supply Exemption the Generator or UDR shall be subject to the Mitigation Net CONE Offer Floor (such value calculated based on the date the SSE Applicant first offers UCAP, in accordance with Section 23.4.5.7.3.7, and adjusted annually in accordance with Section 23.4.5.7 of this Services Tariff.) Prior to the revocation of a Self Supply Exemption and the submission of a report to the Commission's Office of Enforcement (or any successor to its responsibilities,) the ISO shall provide the SSE Applicant an opportunity to explain any statement, information,

or action, and if a statement information or action of the Self Supply LSE, it shall also provide an opportunity to that entity. The ISO cannot revoke the Self Supply Exemption until after the 30 days written notice period has expired, unless ordered to do so by the Commission.

23.4.5.7.15 Forecasts Under the Buyer Side Market Power Mitigation Measures

The rules set forth in this Section 23.4.5.7.15 apply to (i) the ISO's determinations pursuant to Section 23.4.5.7, *et seq*. of ICAP Spot Market Auction forecast prices ("BSM ICAP Forecast") and (ii) Energy and Ancillary Services revenues when determining Unit Net CONE under Sections 23.4.5.7, *et seq*. (collectively for purposes of this Section, a "BSM Forecast"). The rule for Excluded Capacity set forth in Section 23.4.5.7.15.7.3 shall apply to Self Supply Capacity and Additional Self Supply Capacity under Section 23.4.5.7.14.3. The ISO shall post on its website the BSM Forecast inputs determined in accordance with this Section 23.4.5.7.15, subject to any restrictions on the disclosure of Confidential Information or Critical Energy Infrastructure Information, on or before the commencement of the Initial Decision Rounds for the Class Year Study, Cluster Study, Additional SDU Study, and the Expedited Deliverability Study. This posting will include sources of or references for publicly available information "demonstrating with reasonable certainty," as defined in Section 23.4.5.7.15.2, used to develop the BSM Forecast.

23.4.5.7.15.1 For the purposes of Section 23.4.5.7.15, a "positive indicator" that a Generator or UDR project will repair and return to service includes indications that a return to service is, in the ISO's judgment, likely and imminent, such as visible site activity, executed labor or fuel supply arrangements, or unit testing.

23.4.5.7.15.2 For the purposes of Section 23.4.5.7.15, publicly available information "demonstrating with reasonable certainty" shall be limited to information that has been released, authorized, capitulated, or endorsed by an individual or entity having the authority or right to take specific, definitive, actions; and – if such

information is contested, to take unilateral actions regarding the operational status of the facility.

23.4.5.7.15.3 When establishing a BSM Forecast, the ISO shall incorporate the parameters and inputs identified in the following subsections. The ISO shall make assumptions necessary to account for any other value or input not expressly addressed in the following subsections in accordance with ISO Procedures.

23.4.5.7.15.3.1 When establishing a BSM Forecast, the ISO shall include Existing Units and Additional Units, as defined in Sections 23.4.5.7.15.4 and .5, less Omitted Units, as defined in Section 23.4.5.7.15.6.

23.4.5.7.15.3.2 When establishing a BSM Forecast, the ISO shall utilize the Load forecast as set forth in the most recently published Load and Capacity Data (Gold Book), or as most recently posted to the ISO's public website and in accordance with ISO Procedures.

23.4.5.7.15.3.3 When determining a BSM ICAP Forecast, the ISO shall reflect Special Case Resource enrollment at a level consistent with average enrollment over the 3 prior Capability Years and Distributed Energy Resource participation in the Installed Capacity market at a level projected in accordance with ISO Procedures.

23.4.5.7.15.3.4 When determining a BSM ICAP Forecast, the ISO shall identify the projected ICAP Demand Curve by applying the "inflation index" as defined in Section 23.4.5.7.4. When determining a BSM ICAP Forecast for an Indicative Buyer-Side Mitigation Exemption Determination under Sections 23.4.5.7.2.2 and 23.4.5.7.2.4 when the Commission has not yet accepted the first ICAP Demand

Curve to apply specifically to the Mitigated Capacity Zone in which the NCZ Examined Project is located, such inflation rate shall be applied to the ICAP Demand Curve the ISO filed pursuant to Services Tariff Section 5.14.1.2.2.4.11.

23.4.5.7.15.4 Existing Units

Except for the Generators and UDR projects that are excluded without limitation under an exception set forth in Section 23.4.5.7.15.7, the ISO shall identify "Existing Units" as the set of Generators and UDR projects identified in the ISO's most-recently published Gold Book that have CRIS, and are operating at the time that the ISO determines the forecast; including but not limited to Generators in Forced Outage or Inactive Reserve status.

23.4.5.7.15.5 Additional Units

Subject to the exceptions set forth in Section 23.4.5.7.15.7, the ISO shall identify "Additional Units" as each Generator and UDR project that has been found to be exempt from an Offer Floor as described in Section 23.4.5.7.15.5.2 or (i) has previously offered to supply UCAP, (ii) has CRIS, (iii) is not in Existing Units, and (iv) if a Generator, is in an ICAP Ineligible Forced Outage, Mothball Outage, or Retired; if either: (a) the ISO concludes in its sole judgment that there are sufficient positive indicators that the Generator or UDR project will repair and return to service, or (b) the ISO determines that a return to service of the Generator or UDR project would have a positive Net Present Value as set forth in Section 23.4.5.7.15.8.

23.4.5.7.15.5.1 When establishing a BSM Forecast, the inclusion of Generators and UDR projects identified pursuant to Section 23.4.5.7.15.5 (b) as Additional Units shall reflect the persistence of their operation as being contingent on the projected recovery of their forecasted Going Forward Costs.

23.4.5.7.15.5.2 When the ISO establishes a BSM Forecast to complete the BSM determinations for a Class Year Study, Cluster Study, Additional SDU Study or Expedited Deliverability Study, the ISO shall not double-count exemptions. The ISO, in consultation with the Market Monitoring Unit, shall include for each set of decision round determinations: (i) all Examined Facilities that the ISO has previously exempted from an Offer Floor as a Public Policy Resource under Section 23.4.5.7.3.1 in a Class Year Study, Cluster Study, or Additional SDU Study or Expedited Deliverability Study in the first Capability Year in which the Examined Facility was granted such exemption, provided, however, for any exemption granted to an Examined Facility as a Public Policy Resource under Section 23.4.5.7.3.1 prior to the most recently completed Class Year Study or Cluster Study, the ISO shall exclude the Examined Facility if it has determined it is reasonable to project the Examined Facility will not enter the market, and (ii) all Examined Facilities that the ISO determines will receive a Part A Exemption in the currently ongoing Class Year Study, Cluster Study, Additional SDU Study or Expedited Deliverability Study until and unless an Examined Facility rejects its cost allocation or otherwise drops out of such Class Year Study, Cluster Study, Additional SDU Study or Expedited Deliverability Study. Any Examined Facility that was granted an exemption by the ISO in a previously completed Class Year Study, Cluster Study, Additional SDU Study, or Expedited Deliverability Study pursuant to Section 23.4.5.7.2(a) if issued prior to the start of Class Year 2019, Section 23.4.5.7.2(b), Section 23.4.5.7.2(c) or Section 23.4.5.7.2(d) shall also be included in the BSM Forecast for each set of decision round determinations for

such Class Year Study, Cluster Study, Additional SDU Study, or Expedited Deliverability Study if the ISO has determined that 5% or more of its respective total project's costs have been spent.

23.4.5.7.15.6 Omitted Units

Subject to the exceptions set forth in Section 23.4.5.7.15.7, the ISO shall identify "Omitted Units" as the set of Generators and UDR projects that meet the criteria in the following subsections.

23.4.5.7.15.6.1 Generators and UDR projects (i) that have transferred CRIS; (ii) for which the CRIS has expired; (iii) that have CRIS for which a request has been received by the ISO for an evaluation of a CRIS transfer from another location in the Class Year Study or Cluster Study commencing in a calendar year in or preceding the Mitigation Study Period; or (iv) that are an expected transferor of transferred CRIS at the same location. For any CRIS transfer described in (iii) or (iv) of this Section, the transferor or the transferee must have notified the ISO of the transfer pursuant to Section 25.9.4 of Attachment S or Section 40.18.3 of Attachment HH to the OATT and the transfer must be reasonably expected to be effective on a date within the Mitigation Study Period.

23.4.5.7.15.6.2 Generators in ICAP Ineligible Forced Outages (even if resulting from Catastrophic Failures), Mothball Outages, or that are Retired; provided they are not identified under Section 23.4.5.7.15.5 as an Additional Unit or an exception under Section 23.4.5.7.15.7.

23.4.5.7.15.6.3 Generators that have submitted a Generation Deactivation Notice, beginning with the proposed deactivation date identified in such notice, provided

that: (i) the ISO does not identify sufficient positive indicators that the Generator will repair and return to service and (ii) the ISO determines that a return to service or continued operation of the Generator does not have a positive Net Present Value as set forth in Section 23.4.5.7.15.8.

23.4.5.7.15.7 Exceptions

The rules set forth in the following subsections take precedence over the rules described elsewhere in Section 23.4.5.7.15 under the facts and circumstances defined therein.

23.4.5.7.15.7.1 Generators that have submitted a Generation Deactivation Notice, for which the ISO has not yet completed its Short-Term Assessment of Reliability or Generation Deactivation Assessment, shall not be identified by the ISO as Omitted Units, unless there is publicly available information demonstrating with reasonable certainty that the Generator or UDR project will indefinitely cease operation.

23.4.5.7.15.7.2 Initiating Generators with an associated Generator Deactivation Reliability Need for which a Short-Term Reliability Process Solution has not yet been identified, RMR Generators, and Interim Service Providers that are required to keep their generating unit(s) in-service, shall be included in Existing Units for the expected duration of such Generator Deactivation Reliability Need with which they are associated. Such Generators shall also be included in Existing Units beyond the expected duration of the Generator Deactivation Reliability Need if either: (a) the ISO determines, in its sole judgment, that a return to service or continued operation of the Generator has a positive Net Present Value as set forth in Section 23.4.5.7.15.8, or (b) there is publicly available information

demonstrating with reasonable certainty that the Generator will continue operation.

23.4.5.7.15.7.3 Except for those included in Existing Units pursuant to Section 23.4.5.7.15.7.2, Generators and UDR projects for which there is publicly available information demonstrating with reasonable certainty that they will indefinitely cease operation, shall be identified as Excluded Capacity beginning with the date determined by the ISO to be consistent with the expected cessation of operations.

23.4.5.7.15.7.4 Generators and UDR projects for which there is publicly available information demonstrating with reasonable certainty that (a) they will return to service shall be included in Additional Units beginning with the date determined by the ISO to be consistent with its expected return to service, or (b) they will continue operations shall be included in Additional Units until the date determined by the ISO to be consistent with its expected continuation of operations.

23.4.5.7.15.7.5 Where determined by the ISO in its sole judgment to be reasonable, the additional capability associated with the repair of a Generator or UDR project that has been operating under a long term partial derate (such as due to the delay or deferral of repairs) may be treated as if it were in and of itself a separate Generator or UDR project in an ICAP Ineligible Forced Outage for the purposes of Section 23.4.5.7.15. In such instances, the net present value of the investment required to for the Generator or UDR facility to return to its original

capability or capability prior to the long term partial derate shall be evaluated in place of the cost of returning to service.

23.4.5.7.15.7.6 The ISO shall not be required pursuant to Section 23.4.5.7.15 to determine whether a return to service or continued operation would have a positive Net Present Value as set forth in Section 23.4.5.7.15.8 for: (i) Generators in ICAP Ineligible Forced Outages that the ISO determined to have resulted from a Catastrophic Failure; and (ii) Generators that are Retired, provided that in the case of (ii), in the ISO's sole judgment, (a) the Generator was subject to actions that rendered it permanently inoperable, (b) the reversal of such actions would be a nontrivial undertaking, and (c) the ISO has received confirmation from it that it has permanently ceased operations.

23.4.5.7.15.7.7 The production and sale of energy from Generators and UDR projects that only have ERIS and no CRIS, or that will have ERIS only after a transfer of CRIS, for which the ISO has received notice or made a determination in the Class Year or Cluster Study as described in the next sentence, shall be modeled in the BSM Forecasts, but such units shall be excluded from the BSM ICAP Forecast. In accordance with Attachment S or HH of the OATT, the ISO must have received notice that the transaction is final if a transfer of CRIS at the same location, or have determined the facility receiving the transfer is deliverable and such transferee is either in the Class Year or Cluster Study being examined, or remained in a prior Class Year or Cluster Study at the time of its completion, if a transfer of CRIS from a different location.

23.4.5.7.15.8 Net Present Value Analysis

Where required by Section 23.4.5.7.15, the ISO shall determine if a Generator or UDR project that potentially could return to service or continue in operation would have a positive net present value under ISO-predicted market conditions and recognizing the entry of projects in the current Class Year or Cluster Study and those that remained in prior Class Years or Cluster Studies at the time of their completion, in accordance with ISO Procedures. If the ISO-estimated net present value is greater than zero, then the criterion of this Section will be considered to have been met.

23.4.5.7.15.8.1 The ISO's net present value analysis shall consider, at a minimum: (a) the ISO-estimated costs and opportunity costs associated with returning a Generator or UDR project to service if the unit is not currently operating, and of continued operation through the end of the Mitigation Study Period, or the end of the investment horizon as reasonably determined by the ISO, whichever is of greater length (including, if applicable, the expected lost revenues of the rest of the portfolio of the Installed Capacity Supplier attributable to reductions in ICAP Spot Market Auction prices caused by the Generator or UDR project's return to service); (b) the ISO-estimated revenues, over the same time period, from the production and sale of Energy, Ancillary Services, and capacity, and (c) the effect that additional risk associated with the age, condition, and location of the Generator or UDR project may have on the required return on investment.

23.4.5.7.15.8.2 The ISO's net present value analysis shall be for a period beginning after the reasonably anticipated commencement of the Initial Decision Round but before the starting Capability Period of the Mitigation Study Period,

through the end of Mitigation Study Period, or until the investment horizon as reasonably assumed by the ISO, whichever is of greater length.

23.4.5.7.15.8.3 The ISO shall consider data received from the Generator and UDR project for which it is performing a net present value analysis pursuant to this Section 23.4.5.7.15.8, and information received pursuant to Section 38.25 of the OATT, along with any new, updated, or relevant information that the ISO, in its sole judgment and in accordance with ISO Procedures, has verified is reasonable and accurate. If the ISO has not timely received sufficient information from the owner or representative of a Generator or UDR project, or if the ISO has received information but determined it is not suitable or reliable to be used for the purposes of a net present value analysis pursuant to Section 23.4.5.7.8, the ISO can substitute suitable estimated data, or identify the Generator or UDR project as Omitted Units.

23.4.5.8 RMR Agreement Capacity Price and Offer Requirements

23.4.5.8.1 All ISP UCAP MW shall be offered in each ICAP Spot Market Auction. All UCAP from an RMR Generator shall be offered in each ICAP Spot Market Auction, except if and only to the extent expressly authorized in an RMR Agreement due to the existence of a commitment under a bilateral agreement that (a) was effective at the time the RMR Agreement became effective and (b) is effective and executory, requiring the provision of UCAP, for the Obligation Procurement Period.

23.4.5.8.2 Except as provided in Section 23.4.5.7.12, all UCAP offered by an RMR Generator shall be offered at $0.00/kW-month.

23.4.6 Virtual Bidding Measures

23.4.6.1 Purpose

The provisions of this Section 23.4.6 specify the market monitoring and mitigation measures applicable to "Virtual Bids." "Virtual Bids" are bids to purchase or supply energy that are not backed by physical load or generation that are submitted in the ISO Day-Ahead Market in accordance with the procedures and requirements specified in the ISO Services Tariff.

To implement the mitigation measures set forth in this Section 23.4.6, the ISO shall monitor and assess the impact of Virtual Bidding on the ISO Administered Markets.

23.4.6.2 Implementation

23.4.6.2.1 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 23.4.6):

(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: (zonal $LBMP_{real\ time}$ - zonal $LBMP_{day\ ahead}$). 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 23.4.6.

(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 23.4.6.2.1 (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 23.4.6.2.1 (1), above.

23.4.6.2.2 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, and that (ii) the Virtual Bidding practices of one or more Market Participants has contributed to an unwarranted divergence of LBMPs 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 the foregoing conditions are not met.

23.4.6.3 Description of the Measure

23.4.6.3.1 If the ISO determines that the conditions specified in Section 23.4.6.2 exist, the ISO may limit the hourly quantities of Virtual Bids for supply or load that may be offered in a zone by a Market Participant whose Virtual Bidding practices have been determined to contribute to an unwarranted divergence of LBMPs between the Day-Ahead and Real-Time Markets. Any such limitation shall be set at such level that, and shall remain in place for such period as, in the best judgment of the ISO, would be sufficient to prevent any unwarranted divergence between Day-Ahead and Real-Time LBMPs.

23.4.6.3.2 As part of the foregoing determination, the ISO shall request explanations of the relevant Virtual Bidding practices from any Market Participant submitting such Bids. Prior to imposing a Virtual Bidding quantity limitation as specified above, the ISO shall notify the affected Market Participant of the limitation.

23.4.6.4 Limitation of Virtual Bidding

If the ISO determines that such action is necessary to avoid substantial deviations of LBMPs between the Day-Ahead and Real-Time Markets, the ISO may impose limits on the quantities of Virtual Bids that may be offered by all Market Participants. Any such restriction shall limit the quantity of Virtual Bids for supply or load that may be offered by each Market Participant by hour and by zone. Any such limit shall remain in place for the minimum period necessary to avoid substantial deviations of LBMPs between the Day-Ahead and Real-Time Markets, or to maintain the reliability of the New York Control Area.

23.4.7 Increasing Bids in Real-Time for Incremental Energy Scheduled Day-Ahead or Decreasing Bids in Real-Time for Day-Ahead Scheduled Incremental Energy Withdrawals

23.4.7.1 Purpose

This Section 23.4.7 specifies the monitoring applicable and the mitigation measures that may be applicable to a Market Party with submitted Incremental Energy Bids in the real-time market that exceed the Incremental Energy Bids made in the Day-Ahead Market (or mitigated Day-Ahead Incremental Energy Bids where appropriate), for a portion of the Capacity of one or more of its Generators or Aggregations that has been scheduled in the Day-Ahead Market.

This Section 23.4.7 also specifies the monitoring applicable and the mitigation measures that may be applicable to a Market Party with submitted Bids in the real-time market that are less than the Incremental Energy Bids made in the Day-Ahead Market (or mitigated Day-Ahead

Incremental Energy Bids where appropriate), for one or more of its Generators or Aggregations that has been scheduled in the Day-Ahead Market to withdraw Energy.

The purpose of the Services Tariff rules authorizing the submission of Incremental Energy Bids in the real-time market that exceed the Incremental Energy Bids made in the Day-Ahead Market (or mitigated Day-Ahead Incremental Energy Bids where appropriate), of the portion of the Capacity of a Market Party's Generator that was scheduled in the Day-Ahead Market is to permit the inclusion of additional costs of providing incremental Energy in real-time Incremental Energy Bids for Generators scheduled in the Day-Ahead Market, where the additional costs of providing incremental Energy were not known prior to the close of the Day-Ahead Market.

The purpose of the Services Tariff rules authorizing the submission of Incremental Energy Bids in the real-time market less than the Incremental Energy Bids made in the Day-Ahead Market (or mitigated Day-Ahead Incremental Energy Bids where appropriate), of the portion of the Capacity of a Market Party's Generator or Aggregation that was scheduled to withdraw energy in the Day-Ahead Market is to permit changes in opportunity costs to be reflected in real-time Incremental Energy Bids for Generators or Aggregations scheduled to withdraw energy in the Day-Ahead Market, where the opportunity costs of withdrawing incremental Energy has changed relative to the opportunity costs expected prior to the close of the Day-Ahead Market.

23.4.7.2 Monitoring and Implementation

23.4.7.2.1 The ISO will monitor Market Parties for unjustified interactions between a Market Party's virtual bidding and the submission of real-time Incremental Energy Bids that exceed the Incremental Energy Bids submitted in the Day-Ahead Market (or mitigated Day-

Ahead Incremental Energy Bids where appropriate), for the portion of a Generator's or an Aggregation's Capacity that was scheduled in the Day-Ahead Market.

If the Market Party has a scheduled Virtual Load Bid for the same hour of the Dispatch Day as the hour for which submitted real-time Incremental Energy Bids exceeded the Incremental Energy Bids submitted in the Day-Ahead Market (or mitigated Day-Ahead Incremental Energy Bids where appropriate), for a portion of its Generator's or Aggregation's Capacity that was scheduled in the Day-Ahead Market, and any such real-time Incremental Energy Bids exceed the reference level for those Bids that can be justified after-the-fact by more than:

(i) the lower of $100/MWh or 300%; or

(ii) if the Market Party's Generator or Aggregation is located in a Constrained Area for intervals in which an interface or facility into the area in which the Generator or Aggregation is located has a Shadow Price greater than zero, then a threshold calculated in accordance with Sections 23.3.1.2.2.1 and 23.3.1.2.2.2 of these Mitigation Measures;

and a calculation of a virtual market penalty pursuant to the formula set forth in Section 23.4.3.3.4 of these Mitigation Measures for the Market Party would produce a penalty in excess of $1000, then the mitigation measure specified below in Section 23.4.7.3.1 shall be imposed for the Market Party's Generator or Aggregation, along with a penalty calculated in accordance with Section 23.4.3.3.4 of these Mitigation Measures. The application of a penalty under Section 23.4.3.3.4 of these Mitigation Measures shall not preclude the simultaneous application of a penalty pursuant to Section 23.4.3.3.3 of these Mitigation Measures.

23.4.7.2.2 The ISO will monitor Market Parties for unjustified interactions between a Market Party's virtual bidding and the submission of real-time Incremental Energy Bids that are less than the Incremental Energy Bids made in the Day-Ahead Market (or mitigated Day-Ahead Incremental Energy Bids where appropriate), for one or more of its Generators or Aggregations that has been scheduled in the Day-Ahead Market to withdraw Energy.

If the Market Party has a scheduled Virtual Supply Bid for the same hour of the Dispatch Day as the hour for which submitted real-time Incremental Energy Bids at a price that is lower than the Incremental Energy Bids submitted in the Day-Ahead Market (or mitigated Day-Ahead Incremental Energy Bids where appropriate), for one or more of its Generators or Aggregations that has been scheduled in the Day-Ahead Market to withdraw Energy, and any such real-time Incremental Energy Bids is less than the reference level for those Bids that can be justified after-the-fact by more than:

(i) the lower of $100/MWh or 300%; provided however, that Bids to withdraw Incremental Energy that have an associated reference level that is between -$25 and $25 per MWh (inclusive) shall instead be subject to a threshold of $75/MWh; or

(ii) if the Market Party's Generator or Aggregation is located in a Constrained Area for intervals in which an interface or facility into the area in which the Generator, Aggregation or generation is located has a Shadow Price greater than zero, then a threshold calculated in accordance with Sections 23.3.1.2.2.1 and 23.3.1.2.2.2 of these Mitigation Measures;

and a calculation of a virtual market penalty pursuant to the formula set forth in Section 23.4.3.3.4 of these Mitigation Measures for the Market Party would produce a penalty in excess

of $1000, then the mitigation measure specified below in Section 23.4.7.3.1 shall be imposed for the Market Party's Generator or Aggregation, along with a penalty calculated in accordance with Section 23.4.3.3.4 of these Mitigation Measures. The application of a penalty under Section 23.4.3.3.4 of these Mitigation Measures shall not preclude the simultaneous application of a penalty pursuant to Section 23.4.3.3.3 of these Mitigation Measures.

23.4.7.3 Mitigation Measure

23.4.7.3.1 If the ISO determines that the conditions specified in Section 23.4.7.2.1 exist the ISO shall revoke the opportunity for any bidder of that Generator or Aggregation to submit Incremental Energy Bids in the real-time market that exceed the Incremental Energy Bids submitted in the Day-Ahead Market (or mitigated Day-Ahead Incremental Energy Bids where appropriate), for portions of that Generator's or Aggregation's Capacity that were scheduled Day-Ahead.

If the ISO determines that the conditions specified in Section 23.4.7.2.2 exist the ISO shall revoke the opportunity for the Market Party and its Affiliates to submit Virtual Bids in the Load Zone(s) where the Withdrawal-Eligible Generator(s) or Aggregations that include Withdrawal-Eligible Generator(s) that has been scheduled in the Day-Ahead Market to withdraw Energy, and for which the Market Party submitted real-time Incremental Energy Bids that were less than the Incremental Energy Bids made in the Day-Ahead Market, are located.

23.4.7.3.1.1 The first time the ISO revokes the opportunity for bidders of a Generator or Aggregation to submit Incremental Energy Bids in the Real-Time Market that exceed the Incremental Energy Bids submitted in the Day-Ahead Market (or mitigated Day-Ahead Incremental Energy Bids where appropriate), for portions of

that Generator's or Aggregation's Capacity that were scheduled Day-Ahead, mitigation shall be imposed for 90 days. The 90 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.

The first time the ISO revokes the opportunity for the Market Party and its Affiliates to submit Virtual Bids in the Load Zone(s) where the Generator(s) or Aggregation(s) that has been scheduled in the Day-Ahead Market to withdraw Energy, and for which the Market Party submitted real-time Incremental Energy Bids that were less than the Incremental Energy Bids made in the Day-Ahead Market, are located, mitigation shall be imposed for 90 days. The 90 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.

23.4.7.3.1.2 Any subsequent time the ISO revoked the opportunity for bidders of a Generator or an Aggregation to submit Incremental Energy Bids in the Real-Time Market that exceed the Incremental Energy Bids submitted in the Day-Ahead Market or mitigated Day-Ahead Incremental Energy Bids where appropriate, for portions of that Generator's or Aggregation's Capacity that were scheduled Day-Ahead, mitigation shall be imposed for 180 days. The 180 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.

Any subsequent time the ISO revokes the opportunity for the Market Party and its Affiliates to submit Virtual Bids in the Load Zone(s) where the Generator(s) or Aggregation(s) that has been scheduled in the Day-Ahead Market

to withdraw Energy, and for which the Market Party submitted real-time Incremental Energy Bids that were less than the Incremental Energy Bids made in the Day-Ahead Market, are located, mitigation shall be imposed for 180 days. The 180 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.

23.4.7.3.1.3 If bidders of a Generator or an Aggregation that has previously been mitigated under this Section 23.4.7.3 become and remain continuously eligible to submit Incremental Energy Bids in the Real-Time Market that exceed the Incremental Energy Bids submitted in the Day-Ahead Market or mitigated Day-Ahead Incremental Energy Bids where appropriate, for portions of that Generator's or Aggregation's Capacity that were scheduled Day-Ahead, for a period of one year or more, then the ISO shall apply the mitigation measure set forth in Section 23.4.7.3 of the Mitigation Measures as if the Generator or Aggregation had not previously been subject to this mitigation measure.

23.4.7.3.1.4 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 in this Section 23.4.7.3 are required to inform the new Market Party that the Generator or Aggregation is subject to mitigation under this measure, and to inform the new Market Party of the expected duration of such mitigation.

23.4.8 Duration of Mitigation Measures

Except as specified in Section 23.4.5 of this Attachment H, any mitigation measure imposed as specified above shall expire not later than six months after the occurrence of the conduct giving rise to the measure, or at such earlier time as may be specified by the ISO.

23.5 Other Mitigation Measures

23.5.1 Facilitation of Real-Time Mitigation in Constrained Areas

To facilitate the application of the Real-Time mitigation measures specified in this Attachment H for Constrained Areas, all Generators located in a Constrained Area that are capable of doing so shall respond to RTD Base Point Signals, unless such a Generator is subject to contractual obligations in existence prior to June 1, 2002 that would preclude such operation.

23.5.2 Market Power Mitigation Measures Applicable to In-City Unit Commitments for Local Reliability

23.5.2.1 If an In-City Generator is scheduled in any hour in the Day-Ahead Market to meet the reliability needs of a local system, the ISO will set the In-City Generator's Start-Up Bid to the lower of the Bid or the applicable reference level, which may include a Start-Up reference level calculated in accordance with Section 23.3.1.4.4.3 of these Mitigation Measures. In each hour an In-City Generator is scheduled in the Day-Ahead Market to meet the reliability needs of a local system, the ISO will set the In-City Generator's Minimum Generation Bid to the lower of the Bid or the applicable reference level.

23.5.3 Market Power Mitigation Measures Applicable to Sales of Spinning Reserves

23.5.3.1 Local reliability rules require that specified amounts of Spinning Reserves be provided by In-City Generators or Aggregations. The Spinning Reserve-capable portion of each Generator or Aggregation located in New York City must be made available to the ISO for purposes of meeting the New York City Spinning Reserve requirement.

23.5.3.2 The market power mitigation measures applicable to Spinning Reserves will be implemented when the ISO's least-cost dispatch requires that one or more of the Generators or Aggregations located in New York City be committed to meet the In-City Spinning Reserve requirement. For any day that an In-City Generator or Aggregation is committed to meet the In-City Spinning Reserve requirement under circumstances where the Generator or Aggregation would not otherwise have been committed under the ISO's least-cost dispatch, the market power mitigation measures applicable to unit commitments, as described in Section 23.5.2, would apply.

23.5.4 FERC-Ordered Measures

In addition to any mitigation measures specified above, the ISO shall administer, and apply when appropriate in accordance with their terms, such other mitigation measures as it may be directed to implement by order of the FERC.

23.6 RMR Generator and Interim Service Provider Energy and Ancillary Service Market Participation Rules

The rules in this Section 23.6 that address Interim Service Providers apply to Interim Service Providers that are required to keep generating unit(s) in service.

Interim Service Providers that are only required to keep their step-up transformer(s) and/or other system protection equipment in service are not subject to the bidding, reference level development, or mitigation provisions of this Section 23.6, but may be evaluated by the ISO for possible physical withholding and may be assessed a financial penalty for physical withholding in accordance with these Market Mitigation Measures if the Market Party fails to keep the step-up transformer(s) and/or other system protection equipment that the ISO designates in service.

23.6.1 Submission of Bids for RMR Generators and Interim Service Providers

23.6.1.1 A Market Party shall Bid into the Day-Ahead and Real-Time Markets all of the Energy, Operating Reserves and Regulation each RMR Generator or Interim Service Provider is capable of providing by submitting ISO-committed flexible Bids at or below (equally restrictive to or less restrictive than for non-dollar parameters) the Generator's reference levels.

23.6.1.1.1 The ISO develops reference levels for Bids and Bid parameters, including Bid parameters that are not denominated in dollars. *See, e.g.,* Sections 23.3.1.2 and 23.3.1.2.3.3 of these Mitigation Measures. A Market Party must submit Bids for RMR Generators and Interim Service Providers that are consistent with ***all*** reference levels determined by the ISO, including all non-dollar Bid parameters that have been set as reference levels by the ISO.

23.6.1.1.2 If an RMR Generator or Interim Service Provider is not able to operate to a reference level that has been set by the ISO, the Market Party must timely contact the ISO in accordance with ISO Procedures to request a change and explain the need there for.

23.6.1.1.3 If an RMR Generator is not capable of providing all or a portion of its capability flexibly, the ISO and Generator Owner (as defined in Section 38.1 of the OATT) shall specify the restriction in the RMR Agreement. If a new operating constraint arises during the term of an RMR Agreement that prevents the Market Party from offering all or a portion of a RMR Generator's capability via an ISO-committed flexible Bid, then the Market Party must obtain written permission from the ISO to change how it offers the RMR Generator into the ISO Administered Markets. If a new operating constraint arises while a Generator is an Interim Service Provider that prevents the Market Party from offering all or a portion of the Generator's capability via an ISO-committed flexible Bid, the Market Party shall promptly inform the ISO of the change, shall provide all documentation requested by the ISO or by the Market Monitoring Unit, and shall permit the ISO and/or the Market Monitoring Unit to inspect the affected Generator (including all requested plant records) on five days prior notice.

23.6.1.1.4 Market Parties are not required to submit hourly Bids in the Real-Time Market for an RMR Generator or Interim Service Provider that is not capable of being committed by RTC if the RMR Generator or Interim Service Provider was not committed Day-Ahead. If such an RMR Generator or Interim Service Provider was committed Day-Ahead, then the Generator shall be Bid in real-time

for the hours of its Day-Ahead schedule and for additional real-time hours consistent with the Generator's operating capabilities.

23.6.1.1.5 Market Parties shall timely respond to a Supplemental Resource Evaluation ("SRE") or an Out-of-Merit ("OOM") commitment request issued by the ISO or by a Transmission Owner for an RMR Generator or Interim Service Provider.

23.6.1.1.6 If and to the extent a RMR Generator or Interim Service Provider is not available, or is not fully available, the Market Party shall timely notify the ISO of the outage or derate in accordance with ISO Procedures and accurately reflect each RMR Generator's or Interim Service Provider's availability in its Bids.

23.6.1.1.7 The ISO shall monitor Bids that are submitted at prices below an RMR Generator's or Interim Service Provider's reference levels for possible uneconomic overproduction. *See* Section 23.3.1.3. RMR Generators and Interim Service Providers are compensated at the lesser of their Bid or the appropriate Reference Level in accordance with Rate Schedule 8 to the Services Tariff.

23.6.1.2 RMR Generators and Interim Service Providers that are not Installed Capacity Suppliers, or that have not sold all of their Unforced Capacity, are still required to offer all of the Energy, Operating Reserves and Regulation each Generator is capable of providing into each Day-Ahead Market.

23.6.1.3 RMR Generators that provide Voltage Support Services or Restoration Services shall do so in compliance with the relevant provisions of the ISO Tariffs and their RMR Agreement. Interim Service Providers shall provide Voltage Support Services and/or Restoration Services if they provided the service at any

point during the 365 days prior to submitting a Generator Deactivation Notice and are physically capable of providing the service.

23.6.1.4 Market Parties shall not schedule Bilateral Transactions for an RMR Generator's output, unless the Bilateral Transaction is expressly permitted under the relevant RMR Agreement. Market Parties shall not schedule Bilateral Transactions for an Interim Service Provider's output unless they were under an ongoing contractual obligation to do so at the time the Generator Deactivation Notice was submitted.

23.6.1.5 Market Parties may only self-schedule an RMR Generator or Interim Service Provider if they are authorized to do so by the ISO.

23.6.1.6 The responsibilities of the Market Monitoring Unit that are specified in Section 23.6.1 of the Mitigation Measures are also addressed in Section 30.4.6.2.14 of Attachment O.

23.6.2 RMR Generator and Interim Service Provider Energy and Ancillary Service Reference Levels

23.6.2.1 RMR Generator reference levels shall be developed in accordance with the rules specified in these Mitigation Measures, including the provisions of this Section 23.6.2.

23.6.2.2 Interim Service Provider reference levels shall be developed in accordance with the reference level development rules specified in these Mitigation Measures, including the additional rules and authority that are ***expressly*** applied to Interim Service Providers in this Section 23.6.2. The ISO, in consultation with the Market Monitoring Unit, may review and update an Interim Service

Provider's reference levels. The Generator Owner may propose updates to its Interim Service Provider's reference levels. The ISO shall make the ultimate determination with regard to each reference level.

23.6.2.3 In advance of the execution of an RMR Agreement, the ISO, in consultation with the Market Monitoring Unit and Generator Owner, shall review and update the reference levels for each such Generator. The ISO shall make the ultimate determination with regard to each reference level.

23.6.2.3.1 If a possible RMR Generator or Interim Service Provider faces operational constraints the ISO, in consultation with the Market Monitoring Unit and Generator Owner, will develop reference levels that will permit the Generator to operate consistent with the identified constraints, while ensuring that the Generator will be available (a) to resolve the Short-Term Reliability Process Need the Generator is being retained to address, and (b) for economic commitment when appropriate.

23.6.2.4 If an RMR Agreement is executed after the reference level review and update process described above is completed, then during the term of the RMR Agreement, the ISO's authority to change the RMR Generator's reference levels will be limited to the following circumstances:

23.6.2.4.1 Reference levels may be adjusted based on season, the RMR Generator's remaining availability or other factors, to address operational constraints;

23.6.2.4.2 The costs used to develop a reference level (*e.g.*, fuel, emissions, variable operation and maintenance expenses) may be revised whenever the ISO obtains updated or more accurate cost information;

23.6.2.4.3 Opportunity costs may be updated based on actual operating experience during the term of the RMR Agreement;

23.6.2.4.4 If a physical change to the RMR Generator occurs that alters the RMR Generator's capabilities (*e.g.*, damage to the RMR Generator or Capital Expenditures that alter an RMR Generator's capabilities), then the ISO shall determine revised reference levels in consultation with the Market Monitoring Unit and Generator Owner; and

23.6.2.4.5 The ISO and Generator Owner, in consultation with the Market Monitoring Unit, may mutually agree to a reference level change that they expect will better reflect an RMR Generator's actual operating characteristics or variable costs.

23.6.2.5 The Market Party shall timely submit fuel price updates and fuel type updates to the ISO so that they can be incorporated to develop accurate reference levels for each RMR Generator or Interim Service Provider.

23.6.2.5.1 If a Market Party fails to timely submit fuel price updates and fuel type updates for an RMR Generator or Interim Service Provider, then the compensation paid for the RMR Generator's operation may be limited by the reference levels that were in place.

23.6.2.5.2 If a Market Party fails to timely update an RMR Generator's or Interim Service Provider's reference levels to reflect cost reductions that are not *de minimis*, and that are required to be reflected, then the ISO may recalculate the Generator's reference levels and true-up the Variable Costs paid to the Generator under Rate Schedule 8 to the Services Tariff consistent with the Generator's

demonstrated costs. The ISO shall inform the Market Monitoring Unit if it performs such a true-up.

23.6.2.6 The responsibilities of the Market Monitoring Unit that are specified in Section 23.6.2 of the Mitigation Measures are also addressed in Section 30.4.6.2.14 of Attachment O.

23.6.3 Mitigation of RMR Generators and Interim Service Providers

23.6.3.1 RMR Generators and Interim Service Providers are required to Bid at or below their reference levels. The ISO shall mitigate all dollar-denominated Bids that exceed a RMR Generator's or Interim Service Provider's currently effective reference levels.

23.6.3.2 If a Market Party submits unit commitment data or non-dollar Bid parameters for an RMR Generator or Interim Service Provider that is/are not consistent with the Generator's reference levels without first requesting an adjustment to the Generator's reference levels from the ISO, then the ISO shall inform the Market Monitoring Unit of the Market Party's behavior and apply all Tariff-authorized mitigation measures, which may include the application of financial penalties in accordance with Section 23.4.3 of these Mitigation Measures.

23.6.3.3 The ISO shall apply all other Tariff-authorized mitigation measures to RMR Generators and Interim Service Providers consistent with the Mitigation Measures.

23.6.4 Other Energy and Ancillary Service Market Rules

23.6.4.1 On and after the execution of an RMR Agreement, and for the duration of its term, a Market Party shall not enter into any new agreement or extend any other agreement that impairs or otherwise diminishes an RMR Generator's ability to comply with obligation under an RMR Agreement, or that limits the ability of an RMR Generator to provide Energy or Ancillary Services directly to the ISO Administered Markets.

23.6.4.2 A Market Party shall not enter into any new agreement or extend any other agreement that impairs, diminishes or limits the ability of an Interim Service Provider to provide Energy or Ancillary Services directly to the ISO Administered Markets.

23.6.4.3 Market Parties shall not enter into, renew or extend bilateral agreements for Energy or Ancillary Services from an RMR Generator during the term of an RMR Agreement.

23.6.4.4 Market Parties shall not enter into, renew or extend bilateral agreements for Energy or Ancillary Services from an Interim Service Provider.

23.6.4.5 RMR Generators and Interim Service Providers are not eligible to receive Energy, Operating Reserves, Regulation or ICAP market revenues. Instead, RMR Generators and Interim Service Providers are compensated in accordance with Rate Schedule 8 to the Services Tariff and associated Tariff Rules for their participation in the ISO Administered Markets.

23.6.5 ISO Authority to Terminate RMR Agreement with Under-Performing RMR Generator and Cease Reimbursing Capital Expenditures

23.6.5.1 The ISO may terminate an RMR Agreement, or may terminate an RMR Agreement with regard to one of the RMR Generators that is subject to an RMR Agreement if any of the following conditions occur:

(a) Owner (as defined in the *Form of Reliability Must Run Agreement* set forth in Appendix C of Attachment FF to the ISO OATT) defaults under the RMR Agreement and fails to timely cure its default;

(b) The RMR Generator fails to meet one or more of the Minimum Operating Standards set forth in the RMR Agreement (the Minimum Availability Standard, or the Minimum Performance Standard, or the Operation to Address the Reliability Need Standard); or

(c) The RMR Generator fails to operate as requested when it is called upon by the ISO or by a Transmission Owner to address the Short-Term Reliability Process Need that it was retained to address on three or more occasions over the term of an RMR Agreement.

23.6.5.2 If the ISO terminates an RMR Agreement for one of the reasons specified in Section 23.6.5.1 above, then it shall cease repaying the cost of any Capital Expenditures that were incurred at or for the terminated RMR Generator(s) unless the ISO is otherwise instructed by the Commission.

23.6.5.3 Rules for concluding the obligations of an Interim Service Provider early are set forth in Section 38.13 of the OATT.

23.7 Bid Restrictions for Incremental Energy Bids and Minimum Generation Bids for NYCA Resources

23.7.1

The rules set forth in this Section 23.7 are necessary to implement the Bid Restrictions set forth in Section 21 of the ISO Services Tariff. These rules apply to Day-Ahead and real-time Incremental Energy Bids and Minimum Generation Bids submitted for NYCA Resources that exceed $1,000/MWh. The rules in Section 23.7 apply in addition to, *not* in lieu of, any other market power mitigation measure, requirement, obligation, penalty or sanction set forth in the ISO's Tariffs.

23.7.2 Cost Comparison

If an Incremental Energy Bid or Minimum Generation Bid submitted on behalf of a NYCA Resource exceeds $1,000/MWh and complies with the requirements of Sections 23.7.3 (for Generators) or 23.7.4 (for Demand Side Resources) below, then the ISO shall compare the Bid to a cost-based reference level developed in accordance with Sections 23.3.1.4.1.3 and/or 23.3.1.4.2.1, and 23.3.1.4.6 of these Mitigation Measures for Generators, or in accordance with Section 23.7.4 for Demand Side Resources, to determine if it must apply a Bid Restriction.

23.7.2.1 If any component of an Incremental Energy Bid exceeds $1,000/MWh or if a Minimum Generation Bid exceeds $1,000/MWh, then the ISO shall use cost-based reference levels to determine if a Bid Restriction should be applied, and to test all components of the Incremental Energy Bid or the Minimum Generation Bid for possible mitigation in accordance with these Mitigation Measures.

23.7.2.1.1 The ISO does not ordinarily include adders above cost in cost-based reference levels. *See* Section 23.3.1.4.1.3 of these Mitigation Measures. If the

ISO ever decides to allow adders above cost to be included in the cost-based based reference levels it uses to determine if a Bid Restriction should be applied, then the combined impact of all of the adders above cost included in the reference level(s) shall be limited to no more than $100/MWh.

23.7.2.2 If the cost-based reference level the ISO uses to perform the comparison is less than or equal to $1,000/MWh, then the ISO shall restrict the Incremental Energy Bid or Minimum Generation Bid that exceeds $1,000/MWh to $1,000/MWh. Some components of an Incremental Energy Bid curve might exceed $1,000/MWh while other components of the Bid curve might be less than $1,000/MWh. If so, the Bid Restriction will apply to the components of the Incremental Energy Bid curve that exceed $1,000/MWh, for which the associated cost-based reference level is less than or equal to $1,000/MWh.

23.7.2.2.1 The NYISO shall test all Incremental Energy Bids and Minimum Generation Bids that have been restricted to $1,000/MWh for possible mitigation in accordance with the rules set forth in these Mitigation Measures.

23.7.2.3 If the cost-based reference level the ISO uses to perform the comparison is greater than $1,000/MWh but not more than $2,000/MWh, then the ISO shall use the Incremental Energy Bids and Minimum Generation Bids that are less than or equal to that cost-based reference level in its Day-Ahead Market or Real-Time Market (as appropriate). Bids that exceed the cost-based reference level that the NYISO uses to perform the comparison shall be reduced to equal the cost-based reference level. This process may result in some components of an Incremental Energy Bid curve being reduced, but not others.

23.7.2.4 If the cost-based reference level the ISO uses to perform the comparison is greater than $2,000/MWh, then the ISO shall use the Incremental Energy Bids and Minimum Generation Bids that are less than or equal to $2,000/MWh in its Day-Ahead Market or Real-Time Market (as appropriate). Incremental Energy Bids and Minimum Generation Bids that exceed $2,000/MWh shall be recorded by the ISO but the Bids shall be restricted to a maximum of $2,000/MWh for use in the ISO's Day-Ahead Market or Real-Time Market (as appropriate).

23.7.2.4.1 Verified Bid costs that exceed $2,000/MWh may be recovered through a Bid Production Cost Guarantee payment in accordance with Section 18 of the ISO Services Tariff.

23.7.2.5 An Energy Storage Resource that submits an Incremental Energy Bid that exceeds $1,000/MWh may be subject to the alternative Bid Restriction specified below if its submitted Incremental Energy Bid curve extends from a Lower Operating Limit that is less than zero MW to an Upper Operating Limit that exceeds zero MW.

Under the circumstances specified above an Energy Storage Resource's Bid(s) to withdraw energy will be restricted to the lower of (a) a value calculated in accordance with the other provisions of this Sections 23.7.2, or (b) the maximum value that will ensure the difference between Bids to withdraw Energy and Bids to inject Energy incorporate the Energy Storage Resource's Roundtrip Efficiency.

23.7.2.6 Cost components of Incremental Energy Bids and Minimum Generation Bids above $1,000/MWh that are not included in the reference level that the ISO

uses to perform the cost comparison in this Section 23.7.2 may be eligible for recovery through a Bid Production Cost Guarantee payment following an after-the-fact review, in accordance with Sections 23.7.3.3 and 23.7.4.6 below.

23.7.3 Submission and verification of Incremental Energy Bids and Minimum Generation Bids above $1,000/MWh, and updates to Generators' cost-based reference levels.

23.7.3.1 All NYCA Generators that submit Incremental Energy or Minimum Generation Bids that exceed $1,000/MWh are required to submit revised fuel type or fuel price information to the NYISO's Market Information System along with their Day-Ahead and real-time Bids in order to facilitate NYISO's review and validation of the Bids that exceed $1,000/MWh. ISO Procedures shall specify the revised fuel type or fuel price information that must be submitted to the NYISO's Market Information System along with the Incremental Energy and Minimum Generation Bids. Failure to submit required fuel type or fuel price information to the NYISO's Market Information System along with an Incremental Energy and/or Minimum Generation Bid that exceeds $1,000/MWh will result in the Bids being automatically rejected by the ISO.

Real-Time Market Bids that include revised fuel type or fuel price information must be submitted prior to market close for the relevant Real-Time Market hour in order to be evaluated. Day-Ahead Market Bids that include revised fuel type or fuel price information must be submitted at least 15 minutes prior to the close of the Day-Ahead Market (*i.e.*, by 4:45 a.m.) in order to be evaluated.

23.7.3.2 Submission of cost information to support Incremental Energy Bids and

Minimum Generation Bids that exceed $1,000/MWh. In order for an Incremental Energy Bid or a Minimum Generation Bid that exceeds $1,000/MWh to be considered verified, cost information sufficient to justify the Bids must be submitted to the ISO and included by the ISO in the Generator's cost-based reference level for the relevant Day-Ahead or Real-Time Market hour.

23.7.3.3 A Market Party shall only be eligible to recover risk adders that were included in the cost-based Incremental Energy or Minimum Generation reference levels that the ISO used to perform the cost comparison described in Section 23.7.2 above for the relevant Day-Ahead or Real-Time Market hour. Other costs that were Bid, but that were not included in the cost-based Incremental Energy or Minimum Generation reference levels that the ISO used to perform the cost comparison described in Section 23.7.2 above, are eligible for recovery through a Bid Production Cost Guarantee payment in accordance with Section 18 of the ISO Services Tariff if the Market Party demonstrates that they were incurred in an after-the-fact review.

23.7.4 Development of Cost Based Reference Levels and Submission of Incremental Energy and Minimum Generation Bids that Exceed $1,000/MWh by eligible Demand Side Resources.

23.7.4.1 These rules apply to Incremental Energy Bids (including incremental Curtailment Bids) and Minimum Generation Bids (including minimum Curtailment initiation Bids) submitted for Demand Side Resources participating in the Day-Ahead Demand Response Program or the Demand Side Ancillary Service Program. No other Demand Side Resources are eligible to submit Incremental Energy Bids or Minimum Generation Bids that exceed $1,000/MWh.

23.7.4.2 Reference Level Development. Market Parties that submit Incremental Energy Bids or Minimum Generation Bids on behalf of Demand Side Resources that want to be able to submit Incremental Energy Bids or Minimum Generation Bids that exceed $1,000/MWh when such Bids are consistent with a Demand-Side Resource's costs must complete the following procedures to develop cost based Incremental Energy and Minimum Generation reference levels for their Demand Side Resource.

At least 30 days prior to the start of the Capability Period for which the Market Party wants to have cost based reference levels in place for an existing Demand Side Resource, or prior to the completion of the ISO's registration process for Demand Side Resources that are entering the NYISO markets for the first time, the Market Party must develop and provide to the ISO a detailed estimate of the Demand Side Resource's incremental costs of providing load reduction and participate in a reference level development consultation with the ISO. *See* Section 23.3.3.1.4 of these Mitigation Measures.

Once a reference level has been developed for a Demand Side Resource, the Market Party is responsible for informing the ISO of substantial changes to its Demand Side Resource's incremental costs of providing load reduction, and must submit updated cost information to the ISO at least annually.

If the ISO does not have an up-to-date cost based reference level in place for a Demand Side Resource, then the Market Party will not be permitted to submit Incremental Energy Bids or Minimum Generation Bids that exceed $1000/MWh for that Demand Side Resource.

23.7.4.3 Process for Submitting Incremental Energy and Minimum Generation Bids that exceed $1,000/MWh. A Market Party that timely developed cost based Incremental Energy and/or Minimum Generation reference levels for its Demand Side Resource in accordance with Section 23.7.4.2 and that determines its Demand Side Resource's incremental cost of providing load reduction is expected to exceed $1,000/MWh for an upcoming Day-Ahead or Real-Time Market day must develop and submit to the ISO an updated, detailed estimate of the Demand Side Resource's incremental costs of providing load reduction and contact the ISO to schedule a reference level consultation by no later than 9:00 a.m. on the day before the close of the relevant Day-Ahead Market or Real-Time Market hour.

23.7.4.4 If the Market Party does not timely submit the information required in Section 23.7.4.3, then the ISO shall restrict an Incremental Energy Bid or Minimum Generation Bid that exceeds $1,000/MWh to $1,000/MWh.

23.7.4.5 Demand Side Resources participating in the Demand Side Ancillary Service Program are not eligible to recover costs associated with providing Incremental Energy or Minimum Generation.

23.7.4.6 Demand Side Resources participating in the Day-Ahead Demand Response Program that complied with the requirements of Section 23.7.4.3 shall only be eligible to recover risk adders that were included in the cost-based Incremental Energy or Minimum Generation reference levels that the ISO used to perform the cost comparison described in Section 23.7.2 above for the relevant Day-Ahead Market hour. Other costs that were Bid, but that were not included in

the cost-based Incremental Energy or Minimum Generation reference levels that the ISO used to perform the cost comparison described in Section 23.7.2 above, are eligible for recovery through a Bid Production Cost Guarantee payment in accordance with Section 18 of the ISO Services Tariff if the Market Party demonstrates that they were incurred in an after-the-fact review.

23.7.5 Information Requests

If the ISO requests additional information about an Incremental Energy Bid or Minimum Generation Bid that exceed $1,000/MWh or about information supporting such a Bid or supporting a proposed change to the associated reference level, the Market Party shall respond promptly to the ISO's request. Failure to promptly respond may prevent the ISO from verifying a cost and including it in a Generator's or a Demand Response Resource's cost based Incremental Energy or Minimum Generation reference level.

23.7.6 Penalties for Submitting Inaccurate Cost Information

Submission of inaccurate cost information to the ISO in support of Incremental Energy or Minimum Generation Bids that exceed $1,000/MWh. A Market Party that submits inaccurate cost information to the ISO for a Generator or Demand Side Resource that causes a market clearing price impact or a guarantee payment impact shall be subject to financial penalties in accordance with Section 23.4.3 of these Mitigation Measures. Submission of inaccurate information that causes a market clearing price or a guarantee payment impact shall be penalized for withholding in accordance with Sections 23.4.3.3.1, 23.4.3.3.1.1 and 23.4.3.3.1.2 of these Mitigation Measures, unless a different method of calculating a penalty applies to the behavior.

23.8 Monitoring of Aggregations

Except for actions that are shown to be consistent with competitive conduct, moving Resources into, out of or between Aggregations, or constituting and dissolving Aggregations (a) in a manner that avoids or reduces the consequences of mitigation or financial sanctions under the ISO's Tariffs, or (b) that enables a Resource, an Aggregation, an Aggregator, an owner, or a Market Party to avoid complying with a Tariff rule, is a violation of this Services Tariff and shall be reported to the Market Monitoring Unit for possible referral to the Federal Energy Regulatory Commission's Office of Enforcement.

23.9 Dispute Resolution

If a Market Party has reasonable grounds to believe that it has been adversely affected because a Mitigation Measure has been improperly applied or withheld, it may utilize the dispute resolution provisions of the ISO Services Tariff to determine whether, under the standards and procedures specified above and in the Plan, the imposition of a Mitigation Measure was or would have been appropriate. In no event, however, shall the ISO be liable to a Market Party or any other person or entity for money damages or any other remedy or relief except and to the extent specified in the Plan.

23.10 Effective Date

These Mitigation Measures shall be effective as of the date they are approved by the FERC.

24 Attachment I

Reserved for future use.

25 Attachment J – Determination of Day-Ahead Margin Assurance Payments and Import Curtailment Guarantee Payments

25.1 Introduction

If a Supplier that is eligible pursuant to Section 25.2 of this Attachment J buys out of a Day-Ahead Energy, Regulation Service or Operating Reserve schedule in a manner that reduces its Day-Ahead Margin it shall receive a Day-Ahead Margin Assurance Payment, except as noted in Sections 25.2, 25.3, 25.4, and 25.5 of this Attachment J. The purpose of such payments is to protect Suppliers' Day-Ahead Margins associated with real-time reductions after accounting for: (i) any real-time profits associated with offsetting increases in real-time Energy, Regulation Service, or Operating Reserve schedules; and (ii) any Supplier-requested real-time de-rate granted by the ISO.

In addition, a Supplier may be eligible to receive an Import Curtailment Guarantee Payment if its Import is curtailed at the request of the ISO as determined pursuant to Section 25.6 of this Attachment J.

25.2 Eligibility for Receiving Day-Ahead Margin Assurance Payments

25.2.1 General Eligibility Requirements for Suppliers to Receive Day-Ahead Margin Assurance Payments

Subject to Section 25.2.2 of this Attachment J, the following categories of Resources bid by Suppliers shall be eligible to receive Day-Ahead Margin Assurance Payments:

(i) all Self-Committed Flexible and ISO-Committed Flexible Generators, other than Energy Storage Resources and Aggregations, that are either online and dispatched by RTD or available for commitment by RTC;

(ii) any Resource, including an Energy Storage Resource or an Aggregation, that is scheduled Out of Merit by the ISO in response to an ISO or Transmission Owner system security need or to permit the ISO to procure additional Operating Reserves;

(iii) any Resource, including an Energy Storage Resource or an Aggregation, internal to the NYCA that is derated or decommitted by the ISO in response to an ISO or Transmission Owner system security need or to permit the ISO to procure additional Operating Reserves;

(iv) Energy Limited Resources or an Aggregation comprised entirely of Energy Limited Resources with an ISO-approved real-time reduction in scheduled output from its Day-Ahead schedule; and

(v) Limited Energy Storage Resources and Aggregations comprised entirely of Limited Energy Storage Resources scheduled to provide Regulation Service, as described in Section 25.3.2 of this ISO Services Tariff.

25.2.2 Exceptions

Notwithstanding Section 25.2.1 of this Attachment J, no Day-Ahead Margin Assurance Payment shall be paid to:

25.2.2.1 a Resource, otherwise eligible for a Day-Ahead Margin Assurance Payment, in hours in which the NYISO has increased the Resource's real-time minimum operating level above the Resource's Day-Ahead Market Energy schedule either: (i) at the Resource's request including through an adjustment to the Resource's self-commitment schedule; or (ii) in order to reconcile the ISO's dispatch with the Resource's actual output or to address reliability concerns that arise because the Resource is not following Base Point Signals; or (iii) an Intermittent Power Resource that depends on wind or solar energy as its fuel.

25.2.2.2 a Resource, otherwise eligible for Day-Ahead Margin Assurance Payments, in hours in which the NYISO has increased the Resource's real-time minimum operating level at the Resource's request, including through an adjustment to the Resource's self-commitment schedule, above the MW level determined by subtracting the Resource's Day-Ahead Market Regulation Service schedule from its Day-Ahead Market Energy schedule.

25.2.2.3 a Resource, otherwise eligible for Day-Ahead Margin Assurance Payments, in hours in which the Resource reduces the MW quantity specified in its real-time Regulation Capacity Bid below its Day-Ahead Market Regulation Service schedule.

25.2.2.4 a Generator, otherwise eligible for Day-Ahead Margin Assurance Payments, for (i) any hour in which the Incremental Energy Bids submitted in the

Real-Time Market for that Generator exceed the Incremental Energy Bids submitted in the Day-Ahead Market, or the mitigated Day-Ahead Incremental Energy Bids where appropriate, for the portion of that Generator's Capacity that was scheduled in the Day-Ahead Market; and (ii) the two hours immediately preceding and the two hours immediately following the hour(s) in which the Incremental Energy Bids submitted in the Real-Time Market for that Generator exceed the Incremental Energy Bids submitted in the Day-Ahead Market, or the mitigated Day-Ahead Incremental Energy Bids where appropriate, for the portion of that Generator's Capacity that was scheduled in the Day-Ahead Market.

25.2.2.5 A Generator that is available for commitment by RTC and otherwise eligible for Day-Ahead Margin Assurance Payments, for (i) any hour in which the Start-Up Bids submitted in the Real-Time Market for that Generator exceed the Start-Up Bids submitted in the Day-Ahead Market, or the mitigated Day-Ahead Start-Up Bids where appropriate, and that Generator was scheduled for Energy in that hour in the Day-Ahead Market; and (ii) the two hours immediately preceding and the two hours immediately following the hour(s) in which the Start-Up Bids submitted in the Real-Time Market for that Generator exceed the Start-Up Bids submitted in the Day-Ahead Market, or the mitigated Day-Ahead Start-Up Bids where appropriate, and that Generator was scheduled for Energy or Regulation Service in that hour in the Day-Ahead Market.

25.2.2.6 A Generator that is available for commitment by RTC and otherwise eligible for Day-Ahead Margin Assurance Payments, for (i) any hour in which the dollar component of the Minimum Generation Bids submitted in the Real-Time

Market for that Generator exceed the dollar component of the Minimum Generation Bids submitted in the Day-Ahead Market, or the dollar component of the mitigated Day-Ahead Minimum Generation Bids where appropriate, and that Generator was scheduled for Energy in that hour in the Day-Ahead Market; and (ii) the two hours immediately preceding and the two hours immediately following the hour(s) in which the dollar component of the Minimum Generation Bids submitted in the Real-Time Market for that Generator exceed the dollar component of the Minimum Generation Bids submitted in the Day-Ahead Market, or the dollar component of the mitigated Day-Ahead Minimum Generation Bids where appropriate, and that Generator was scheduled for Energy in that hour in the Day-Ahead Market.

25.2.2.7 An Energy Storage Resource that: (1) is interconnected to a Local Area Transmission System Facility or a Transmission Facility Requiring ISO Notification that is not identified as ISO Secure or BMS Secure in ISO Procedures; (2) had its output limited in an ISO interconnection study completed after April 4, 2024 to address one or more specifically identified constraints; and (3) is scheduled or dispatched Out-of-Merit by the ISO to inject or withdraw less Energy than its real-time Energy schedule, ISO-issued economic dispatch instruction, or its current injections or withdrawals, in response to an ISO or Transmission Owner request to relieve a constraint on a Local Area Transmission System Facility that was identified as limiting in the Energy Storage Resource's interconnection study.

25.3 Calculation of Day-Ahead Margin Assurance Payments

25.3.1 Formula for Day-Ahead Margin Assurance Payments for Generators and Aggregations, Except for Limited Energy Storage Resources and Aggregations comprised entirely of Limited Energy Storage Resources

Subject to Sections 25.4 and 25.5 of this Attachment J, Day-Ahead Margin Assurance Payments for Generators and Aggregations, except for Limited Energy Storage Resources and Aggregations comprised entirely of Limited Energy Storage Resources, shall be determined by applying the following equations to each individual Generator or Aggregation using the terms as defined in Section 25.3.3:

$$DMAP_{hu} = max\left(0, \sum_{i \in h} CDMAP_{iu}\right)$$

where:

$$CDMAP_{iu} = CDMAPen_{iu} + \sum_{P} CDMAPres_{iup} + CDMAPreg_{iu}$$

25.3.1.1 Energy Contribution for Day-Ahead Margin Assurance Payments

If the Generator's or Aggregation's (i) Day-Ahead schedule is to inject Energy (*i.e.*, greater than zero MW) and its real-time Energy schedule is lower than its Day-Ahead Energy schedule; or (ii) Day-Ahead schedule is to withdraw Energy (*i.e.*, less than zero MW) and its real-time Energy schedule is greater than its Day-Ahead Energy schedule, then:

$$CDMAPen_{iu} = \left((DASen_{hu} - LL_{iu}) * RTPen_{iu} - \int_{LL_{iu}}^{DASen_{hu}} DABen_{hu}\right) * \frac{Seconds_i}{3600}$$

If the Generator's or Aggregation's (i) Day-Ahead Energy schedule is to inject Energy (*i.e.*, greater than zero MW) and its real-time Energy schedule is greater than or equal to its Day-Ahead Energy schedule; or (ii) Day-Ahead Energy schedule is to withdraw Energy (*i.e.*, less than

zero MW), and its real-time Energy schedule is less than or equal to its Day-Ahead Energy schedule; or (iii) Day-Ahead Energy schedule is for zero MW, then:

$$CDMAPen_{iu} = min\left[\left((DASen_{hu} - UL_{iu}) * RTPen_{iu} + \int_{DASen_{hu}}^{UL_{iu}} RTBen_{iu}\right) * \frac{Seconds_i}{3600}, 0\right]$$

25.3.1.2 Operating Reserve Contribution for Day-Ahead Margin Assurance Payments

If the Generator's or Aggregation's real-time schedule for a given Operating Reserve product, p, is lower than its Day-Ahead Operating Reserve schedule for that product then:

$$CDMAPres_{iup} = \left[\left(DASres_{hup} - RTSres_{iup}\right) * \left(RTPres_{iup} - DABres_{hup}\right)\right] * \frac{Seconds_i}{3600}$$

If the Generator's or Aggregation's real-time schedule for a given Operating Reserve product, p, is greater than or equal to its Day-Ahead Operating Reserve schedule for that product then:

$$CDMAPres_{iup} = \left[\left(DASres_{hup} - RTSres_{iup}\right) * \left(RTPres_{iup}\right)\right] * \frac{Seconds_i}{3600}$$

25.3.1.3 Regulation Service Contribution for Day-Ahead Margin Assurance Payments

If the Generator's or Aggregation's real-time Regulation Service schedule is less than its Day-Ahead Regulation Service schedule then:

$$\begin{aligned} CDMAPreg_{iu} &= \left[\left(DASreg_{hu} - RTSreg_{iu}\right) * \left(RTPreg_{iu} - DABreg_{hu}\right)\right] * \frac{Seconds_i}{3600} \\ &+ \left[\left(-1 * RTMreg_{iu}\right) * max\left(0, RTPregm_{iu} - RTBregm_{iu}\right)\right] \end{aligned}$$

If the Generator's or Aggregation's real-time Regulation Schedule is greater than or equal to the Day-Ahead Regulation Service schedule then:

$$CDMAPreg_{iu} = [(DASreg_{hu} - RTSreg_{iu}) * max((RTPreg_{iu} - RTBreg_{iu}), 0)] * \frac{Seconds_i}{3600} + [(-1 * RTMreg_{iu}) * max(0, RTPregm_{iu} - RTBregm_{iu})]$$

25.3.2 Formula for Day-Ahead Margin Assurance Payments for Limited Energy Storage Resources and Aggregations comprised entirely of Limited Energy Storage Resources

Day-Ahead Margin Assurance Payments for Limited Energy Storage Resources and Aggregations comprised entirely of Limited Energy Storage Resources ("Aggregation of LESR") scheduled to provide Regulation Service shall be determined by applying the following equations to each Resource using the terms as defined in Section 25.3.3; *provided, however*, that a Day-Ahead Margin Assurance Payment is payable only for intervals in which the NYISO has reduced the real-time Regulation Service offer (in MWs) of a Limited Energy Storage Resource or an Aggregation of LESR and the NYISO is not pursuing LESR Energy Management for such Resource for such interval, pursuant to ISO Procedures:

If the LESR's or Aggregation of LESR's real-time Regulation Service schedule is less than its Day-Ahead Regulation Service schedule and the real-time Regulation Capacity Market Price is greater than the Day-Ahead Regulation Capacity Bid price then:

$$CDMAPreg_{iu} = [(DASreg_{hu} - RTSreg_{iu}) * (RTPreg_{iu} - DABreg_{hu})] * K_p * \frac{Seconds_i}{3600} + [(-1 * RTMreg_{iu}) * max(0, RTPregm_{iu} - RTBregm_{iu})]$$

If the LESR's or Aggregation of LESR's real-time Regulation Service schedule is less than its Day-Ahead Regulation Service schedule and the real-time Regulation Capacity Market price is less than or equal to the Day-Ahead Regulation Capacity Bid price then:

$$CDMAPreg_{iu} = [(DASreg_{hu} - RTSreg_{iu}) * (RTPreg_{iu} - DABreg_{hu})] * \frac{Seconds_i}{3600} + [(-1 * RTMreg_{iu}) * max(0, RTPregm_{iu} - RTBregm_{iu})]$$

If the LESR's or Aggregation of LESR's real-time Regulation Service schedule is greater than or equal to the Day-Ahead Regulation Service schedule then:

$$CDMAPreg_{iu} = [(DASreg_{hu} - RTSreg_{iu}) * max((RTPreg_{iu} - RTBreg_{iu}),0)] * \frac{Seconds_i}{3600} + [(-1 * RTMreg_{iu}) * max(0, RTPregm_{iu} - RTBregm_{iu})]$$

25.3.3 Terms Used in this Attachment J

The terms used in the formulas in this Attachment J shall be defined as follows:

h is the hour that includes interval *i*;

$DMAP_{hu}$ = the Day-Ahead Margin Assurance Payment attributable in any hour *h* to any Supplier *u*;

$CDMAP_{iu}$ = the contribution of RTD interval *i* to the Day-Ahead Margin Assurance Payment for Supplier *u*;

$CDMAPen_{iu}$ = the Energy contribution of RTD interval *i* to the Day-Ahead Margin Assurance Payment for Supplier *u*;

$CDMAPreg_{iu}$ = the Regulation Service contribution of RTD interval *i* to the Day-Ahead Margin Assurance Payment for Supplier *u*;

$CDMAPres_{iup}$ = the Operating Reserve contribution of RTD interval *i* to the Day-Ahead Margin Assurance Payment for Supplier *u* determined separately for each Operating Reserve product *p*;

$DASen_{hu}$ = Day-Ahead Energy schedule for Supplier *u* in hour *h*;

$DASreg_{hu}$ = Day-Ahead schedule for Regulation Service for Supplier *u* in hour *h*;

$DASres_{hup}$ = Day-Ahead schedule for Operating Reserve product p, for Supplier *u* in hour *h*;

$DABen_{hu}$ = Day-Ahead Energy Bid cost for Supplier *u* in hour *h*, including the Minimum Generation Bid and Incremental Energy Bids;

$DABreg_{hu}$ = Day-Ahead Regulation Capacity Bid price for Supplier *u* in hour *h*;

$DABres_{hup}$ = Day-Ahead Availability Bid for Operating Reserve product *p* for Supplier *u* in hour *h*;

$RTSen_{iu}$ = real-time Energy scheduled for Supplier *u* in interval *i*, and calculated as the arithmetic average of the 6-second AGC Base Point Signals sent to Supplier *u* during the course of interval *i*;

$RTSreg_{iu}$ = real-time schedule for Regulation Service for Supplier *u* in interval *i*.

$RTSres_{iup}$ = real-time schedule for Operating Reserve product *p* for Supplier *u* in interval *i*.

$RTBreg_{iu}$ = real-time Regulation Capacity Bid price for Supplier *u* in interval *i*.

$RTBen_{iu}$ = real-time Energy Bid cost for Supplier *u* in interval *i*, including the Minimum Generation Bid and Incremental Energy Bids.

$RTBregm_{iu}$ = real-time Regulation Movement Bid price for Supplier *u* in interval *i.*

$RTMreg_{iu}$ = real-time Regulation Movement MWs for Supplier *u* in interval *i;*

AE_{iu} = either, (1) when $RTSen_{iu}$ is greater than zero MW, average Energy injections plus average Demand Reductions minus average Energy withdrawals by Supplier *u* in interval *i* but not more than $RTSen_{iu}$ plus Compensable Overgeneration; or (2) when $RTSen_{iu}$ is less than or equal to zero MW, average Energy injections plus average Demand Reductions minus average Energy withdrawals by Supplier *u* in interval *i*;

$RTPen_{iu}$ = real-time price of Energy at the location of Supplier *u* in interval *i*;

$RTPreg_{iu}$ = real-time price of Regulation Capacity at the location of Supplier *u* in interval *i*;

$RTPres_{iup}$ = real-time price of Operating Reserve product *p* at the location of Supplier *u* in interval *i*;

$RTPregm_{iu}$ = real-time Regulation Movement Market Price at the location of Supplier *u* in interval *i;*

LL_{iu} = When the Day-Ahead Energy schedule is to inject, given that $RTSen_{iu} < DASen_{hu}$, either:

(a) $if\ RTSen_{iu} < EOP_{iu}, then\ LL_{iu} = max(min(max(RTSen_{iu}, \min(AE_{iu}, EOP_{iu})), DASen_{hu}), 0)$; or

(b) $if\ RTSen_{iu} \geq EOP_{iu}, then\ LL_{iu} = max(min(RTSen_{iu}, max(AE_{iu}, EOP_{iu}), DASen_{hu}), 0)$

When the Day-Ahead Energy schedule is to withdraw, given that $RTSen_{iu} > DASen_{hu}$:

$$LL_{iu} = min(max(DASen_{hu}, AE_{iu}, EOP_{iu}), RTSen_{iu}, 0)$$

UL_{iu} = When the Day-Ahead Energy schedule is to inject, or the Day-Ahead Energy schedule is zero MW and the real-time Energy schedule is to inject, given that $RTSen_{iu} \geq DASen_{hu}$, either:

(a) $if\ RTSen_{iu} \geq EOP_{iu} \geq DASen_{hu}, then\ UL_{iu} = min\ (RTSen_{iu}, max\ (AE_{iu}, EOP_{iu}))$; or

(b) otherwise, then $UL_{iu} = max(RTSen_{iu}, min(AE_{iu}, EOP_{iu}))$

When the Day-Ahead Energy schedule is to withdraw, or the Day-Ahead Energy schedule is zero MW and the real-time Energy schedule is to withdraw, given that $RTSen_{iu} \leq DASen_{hu}$:

$$UL_{iu} = min\ (RTSen_{iu}, max\ (AE_{iu}, EOP_{iu}))$$

EOP_{iu} = the Economic Operating Point of Supplier *u* in interval *i* calculated without regard to ramp rates;

$Seconds_i$ = number of seconds in interval *i*

KPI_{pi} = the factor derived from the Regulation Service Performance index for Resource *u* for interval *i* as defined in Rate Schedule 3 of this Services Tariff.

25.4 Exception for Generators and Aggregations Lagging Behind RTD Base Point Signals

If an otherwise eligible Generator's or Aggregation's average Actual Energy Injection in an RTD interval (*i.e.*, its Actual Energy Injections averaged over the RTD interval) is less than or equal to its penalty limit for under-generation value for that interval, as computed below, it shall not be eligible for Day-Ahead Margin Assurance Payments for that interval.

The penalty limit for under-generation value is the tolerance described in Section 15.3A.1 of Rate Schedule 3-A of this ISO Services Tariff, which is used in the calculation of the persistent under-generation charge applicable to Generators and Aggregations that are not providing Regulation Service.

25.5 Rules Applicable to Supplier Derates

Suppliers that request and are granted a derate of their real-time Operating Capacity, but that are otherwise eligible to receive Day-Ahead Margin Assurance Payments may receive a payment up to a Capacity level consistent with their revised Emergency Upper Operating Limit or Normal Upper Operating Limit, whichever is applicable. The foregoing rule shall also apply to a Generator or Aggregation otherwise eligible for a Day-Ahead Margin Assurance Payment in hours in which the ISO has derated the Generator's or Aggregation's Operating Capacity in order to reconcile the ISO's dispatch with the Generator's or Aggregation's actual output, or to address reliability concerns that arise because the Generator or Aggregation is not following Base Point Signals. If a Supplier's derated real-time Operating Capacity is lower than the sum of its Day-Ahead Energy, Regulation Services, and Operating Reserve schedules then when the ISO conducts the calculations described in Section 25.3 above, the DASen, DASeg and $DASres_p$ variables will be reduced by REDen, REDreg and $REDres_p$ respectively. REDen, REDreg and $REDres_p$ shall be calculated using the formulas below:

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

$$POTREDen_{iu} = max(DASen_{hu} - RTSen_{iu}, 0)$$

$$POTREDreg_{iu} = max(DASreg_{hu} - RTSreg_{iu}, 0)$$

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

$$REDen_{iu} = \left(POTREDen_{iu} / \left(POTREDen_{iu} + POTREDreg_{iu} + \sum_p POTREDres_{iup}\right)\right) * REDtot_{iu}$$

$$REDreg_{iu} = \left(POTREDreg_{iu} / \left(POTREDen_{iu} + POTREDreg_{iu} + \sum_p POTREDres_{iup}\right)\right) * REDtot_{iu}$$

$$REDres_{iup} = \left(POTREDres_{iup} / \left(POTREDen_{iu} + POTREDreg_{iu} + \sum_p POTREDres_{iup}\right)\right) * REDtot_{iu}$$

where:

$RTUOL_{iu}$ = The real-time Emergency Upper Operating Limit or Normal Upper Operating Limit whichever is applicable of Supplier *u* in interval *i*

$REDtot_{iu}$ = The total amount in MW that Day-Ahead schedules need to be reduced to account for the derate of Supplier *u* in interval *i*

$REDen_{iu}$ = The amount in MW that the Day-Ahead Energy schedule is reduced for the purposes of calculating the Day-Ahead Margin Assurance Payment for Supplier *u* in interval *i*

$REDreg_{iu}$ = The amount in MW that Supplier *u*'s Day-Ahead Regulation Service schedule is reduced for the purposes of calculating the Day-Ahead Margin Assurance Payment in interval *i*

$REDres_{iup}$ = The amount in MW that Supplier *u*'s Day-Ahead Operating Reserve schedule for Operating Reserves product *p* is reduced for the purposes of calculating the Day-Ahead Margin Assurance Payment in interval *i*

$POTREDen_{iu}$ = The potential amount in MW that Supplier *u*'s Day-Ahead Energy schedule could be reduced for the purposes of calculating the Day-Ahead Margin Assurance Payment for Supplier *u* in interval *i*

$POTREDreg_{iu}$ = The potential amount in MW that Supplier *u*'s Day-Ahead Regulation Service schedule could be reduced for the purposes of calculating the Day-Ahead Margin Assurance Payment for Supplier *u* in interval *i*

$POTREDres_{iup}$ = The potential amount in MW that Supplier *u*'s Day-Ahead Operating Reserve Schedule for Operating Reserve product *p* could be reduced for the purposes of calculating the Day-Ahead Margin Assurance Payment for Supplier *u* in interval *i*

All other variables are as defined above.

25.6 Import Curtailment Guarantee Payments

25.6.1 Eligibility for an Import Curtailment Guarantee Payment for an Import Curtailed by the ISO

In the event that the Energy injections for an Import scheduled by RTC or RTD at a Proxy Generator Bus, other than a CTS Enabled Proxy Generator Bus, are Curtailed at the request of the ISO, and (i) the real-time Energy Profile MW is equal to or greater than the Day-Ahead Energy Schedule for that interval, and (ii) the real-time Decremental Bid is less than or equal to the default real-time Decremental Bid amount as established by ISO procedures, then the Supplier or Transmission Customer that is subjected to the Curtailment, in addition to the charge for Energy Imbalance, shall be eligible for an Import Curtailment Guarantee Payment as determined in Section 25.6.2 of this Attachment J. Suppliers scheduling Imports at CTS Enabled Proxy Generator Buses shall not be eligible for Import Curtailment Guarantee payments for those Transactions.

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

A Supplier eligible under Section 25.6.1 of this Attachment J shall receive an Import Curtailment Guarantee Payment for its curtailed Energy injections that is equal to the daily sum of the hourly payments which, for each hour of Import t, is calculated as the greater of the interval payments determined for the hour or zero as seen in the formula below.

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

$$\sum_{h=1}^{N} max\left(\sum_{i=1}^{H}(RTLBMP_{ti} - max(DADecBid_{ti}, 0)) * (DAen_{ti} - RTDen_{ti}) * \frac{S_i}{3600}, 0\right)$$

Where

N = the number of hours in the Dispatch Day

H = the number of intervals in hour h

i = the relevant interval in hour h;

S_i = number of seconds in interval i;

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

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

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

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

26 Attachment K - Creditworthiness Requirements For Customers

This Attachment K applies to all Customers and all applicants seeking to become Customers.

"Customer," as used in this Attachment K, shall also mean an applicant seeking to become a Customer.

26.1 Minimum Participation Criteria

26.1.1 General

To participate in the ISO-Administered Markets, in addition to satisfying any other eligibility requirements set forth in the ISO Tariffs, each Customer must satisfy, and at all times remain in compliance with, the following requirements:

(a) Risk Management. Customer shall maintain current, written risk management policies and procedures that address those risks that could materially and adversely affect Customer's ability to pay its ISO invoices when due, including, but not limited to, credit risks, liquidity risks, and market risks.

(b) Training. Each employee and agent that Bids or schedules in the ISO-Administered Markets on behalf of Customer shall have appropriate training and/or experience to transact on behalf of Customer in the ISO-Administered Markets. In addition, each employee and agent that Bids on Virtual Transactions or TCCs on behalf of Customer shall successfully complete the designated ISO-administered online training course on Virtual Transactions and/or TCCs one time, as applicable; provided, however, this requirement does not apply to a Transmission Owner as a result of its receipt of Net Auction Revenue.

(c) Operational Capabilities. Customer shall have appropriate personnel resources and technical abilities to promptly and effectively respond to all ISO communications and directions related to settlements, billing, credit requirements, and other financial matters.

(d) Financial Capabilities. Customer shall have appropriate experience and resources to satisfy its obligations to the ISO as they become due.

(e) Capitalization. Customer, or its guarantor with the provision of an unlimited guaranty in compliance with Section 26.5.4 of this Attachment K, shall meet the minimum capitalization criteria set forth below or post additional security in accordance with the following:

i. Maintain at least US $10 million in assets or at least US $1 million in tangible net worth as evidenced by Customer's or its guarantor's most recent audited annual financial statements; or

ii. If Customer is unable to meet the minimum capitalization criteria set forth in Section 26.1.1(e)i of this Attachment K, post with the ISO either (1) $200,000 to participate in any/all of the ISO-Administered Markets other than the TCC market, which security Customer may not use to support any ISO credit requirements, or (2) $500,000 to participate in any/all of the ISO-Administered Markets including the TCC market, which security the Customer may not use to support any ISO credit requirements.

The ISO will independently verify that adequate capitalization is being maintained on an annual basis. In addition, if at any time a Customer that satisfied the capitalization requirement set forth in Section 26.1.1(e) above by demonstrating compliance with the criteria set forth in Section 26.1.1(e)i experiences a change in financial position such that Customer no longer satisfies these criteria, Customer shall notify the ISO promptly of this change in financial position and post the appropriate amount of security in accordance with Section 26.1.1(e)ii of this Attachment K.

26.1.2 Annual Certification

Each Customer must demonstrate ongoing compliance with the minimum participation requirements set forth in Section 26.1.1 of this Attachment K by submitting to the ISO on or before April 30 of each year an officer's certificate, signed by an authorized officer of Customer with signatory authority, in a form acceptable to the ISO, certifying that Customer is in compliance with each of the minimum participation requirements. Each NYISO applicant must submit an initial officer's certificate with its Completed Application.

26.1.3 Verification of Risk Management Policies and Procedures

26.1.3.1 Scope

(a) Each applicant applying to participate in the TCC market shall submit its risk management policies and procedures for verification prior to commencing any activity in the TCC market.

(b) Each Customer that participates in the TCC market, except those Customers that solely own Grandfathered Rights, Grandfathered TCCs and/or Fixed Price TCCs, shall submit its risk management policies and procedures to the ISO annually by no later than April 30 of each calendar year.

(c) Each Customer that participates in the TCC market and meets the criteria below shall be subject to annual verification:

i. does not solely own Grandfathered Rights, Grandfathered TCCs and/or Fixed Price TCCs, and

ii. has, for any month in the immediately preceding 36 months, had a concentration of negative or low positive TCCs. For purposes of this Section 26.1.3.1(c)(ii), a

Customer shall be deemed to have a concentration of negative or low positive TCCs if the net amount owed by the Customer to the ISO for "TCC Congestions Rents" on its consolidated invoices for the month is greater than $0 or the net amount owed by the ISO to the Customer for "TCC Congestion Rents" on its consolidated invoices for the month is less than or equal to $50,000.

(d) For Customers that are not already subject to verification as detailed in Section 26.1.3.1(c), the ISO may select 10-20% of those Customers per year for review on a random basis. Customers randomly selected for risk management verification and satisfactorily verified shall be excluded from such verification based on a random selection for the subsequent two years.

(e) A Customer notified by the ISO that it will be subject to verification shall, within two (2) business days of the Customer's receipt of the ISO's notice, submit to the ISO a copy of its current governing risk management policies and procedures.

(f) Where a Customer has not made any material changes to its risk management policies and procedures since its last submission to the ISO, the Customer may submit a certificate to the ISO in lieu of resubmission of its risk management policies and procedures. The certificate must be in a form acceptable to the ISO, be signed by an authorized officer of the Customer, and state that the Customer's risk management policies and procedures have not materially changed since its last submission.

26.1.3.2 Verification Standards and Process

The ISO will assess the Customer's (or applicant's) risk management policies and procedures to confirm those policies and procedures conform to the risk management standards

and practices set forth in this Section 26.1.3.2. Through such assessment, the ISO will verify that:

1. Customer's risk management framework is documented in a risk policy addressing market, credit and liquidity risks that have been approved by the Customer's risk management function, which includes appropriate corporate persons or bodies that are independent of the Customer's trading functions, such as a risk management committee, a designated risk officer, a Customer's board of directors or board committee, or, if applicable, a board of directors or board committee of a Customer's parent company.
2. Customer maintains an organizational structure with clearly defined roles and responsibilities that appropriately, and to the extent practical, segregate trading functions from risk management functions (*e.g.*, segregation of front, middle, and back office functions).
3. Customer has established delegations of authority specifying the transactions into which its traders are allowed to enter.
4. Customer ensures that its traders have adequate training and/or experience relative to their delegations of authority in the systems and markets in which they transact.
5. As appropriate, risk limits are in place to control risk exposures.
6. Reporting is in place to ensure that risks are adequately communicated throughout the organization.
7. Processes are in place for qualified independent review of trading activities.
8. As appropriate, there is periodic valuation or mark-to-market of risk positions.

A Customer subject to risk management verification and satisfactorily verified by the ISO shall inform the ISO of any material change in its risk management policies and procedures within five (5) business days of such change.

For each Customer subject to risk management verification, continued eligibility to participate in the ISO-Administered Markets is conditioned upon the ISO notifying the Customer of successful completion of the ISO's verification; *provided, however,* that if the ISO notifies the Customer in writing that the Customer's risk management policies and procedures did not satisfy the standards set forth in this Section 26.1.3.2, the Customer shall have 30 calendar days to submit revised risk management policies and procedures, which have been revised to address any deficiencies identified by the ISO, prior to the ISO declaring the Customer in default for failure to comply with the creditworthiness requirements of the ISO Tariffs. If, prior to the expiration of such 30 calendar days, the Customer demonstrates to the ISO that it has filed with the Commission an appeal of the ISO's risk management verification determination, then the Customer shall retain its transaction rights and not be declared in default for failure to comply with the creditworthiness requirements of the ISO Tariffs, pending the Commission's determination on the Customer's appeal.

The ISO may retain a third party to perform the review and verification function described in this Section 26.1.3.2. The ISO and any third party it may retain will treat as Confidential Information the documentation provided by a Customer under this Section 26.1.3.2, consistent with the applicable provisions of Attachment F to the ISO OATT.

The ISO shall have the right to charge a Customer subject to verification under this Section 26.1.3 for any costs incurred by the ISO related to the ISO's verification of the Customer's risk management policies and procedures.

26.1.4 ISO Review

A Customer or applicant seeking to become a Customer shall submit to the ISO any information or documentation reasonably required for the ISO to evaluate its experience and resources. If the ISO determines, based on its review of relevant information, that the applicant's participation in the ISO Administered Markets presents an unreasonable credit risk, the ISO may reject applicant's application, notwithstanding applicant's ability to meet other minimum participation criteria, registration requirements, and creditworthiness requirements. The ISO will provide the affected applicant with a written explanation of the reasons the ISO rejected the application. No action by the ISO pursuant to this Section 26.1.4 shall limit in any way the ISO's rights or authority under any other provisions of the ISO Tariffs or applicable law.

26.1.5 Additional Information

Each Customer shall submit to the ISO, upon request, any information or documentation reasonably required for the ISO to monitor and evaluate Customer's creditworthiness and compliance with requirements set forth in the ISO Tariffs, ISO Procedures, and/or ISO Agreements related to settlements, billing, credit requirements, and other financial matters.

26.1.6. Credit Information Sharing Under Order No. 895

The ISO is permitted to share credit-related information of Customers, applicants seeking to become Customers, and their Affiliates with Commission-jurisdictional regional transmission organizations and independent system operators for the purpose of credit risk management and mitigation. This information includes, but is not limited to, (1) lists of Customers with positions in the ISO-Administered markets; (2) reports and metrics around risk and credit exposures; (3) disclosure that a Customer or Affiliate has defaulted on any of its financial or contractual

obligations, failed to pay invoices on a timely basis, or failed to meet a collateral call; (4) information regarding a Customer's or its Affiliate's unresolved credit/collateral issues; (5) information indicating that a Customer or its Affiliate has an increased risk of default, such as instances where a Customer or its Affiliate has experienced a material adverse condition or material adverse change under a Commission-jurisdictional regional transmission organization or independent system operator tariff or related agreement; and (6) any other information on a Customer or its Affiliate that indicates a possible material adverse change in creditworthiness or financial status or an unreasonable credit risk.

The ISO is permitted to use credit-related information received from Commission-jurisdictional regional transmission organizations and independent system operators to the same extent and for the same purposes that it may use information from its Customers and applicants seeking to become Customers under the terms of this Tariff and the OATT. The ISO will treat material received under this provision as Confidential Information.

26.2 Reporting Requirements

26.2.1 All Customers shall be required to comply with the reporting requirements in this Section 26.2.1

26.2.1.1 References

The ISO may require a Customer to provide references from one (1) bank and up to three (3) utilities. A Customer that does not have utility references, may substitute trade payable vendor references.

26.2.1.2 Prior Bankruptcy or Default

A Customer shall inform the ISO of any prior bankruptcy declarations or material defaults by the Customer or its predecessors, subsidiaries, or Affiliates occurring within the previous five (5) years.

26.2.1.3 Investigations

Unless prohibited by law, a Customer shall inform the ISO of the existence of any ongoing investigations of which the Customer is aware by the Securities and Exchange Commission, the Department of Justice, the Federal Energy Regulatory Commission, or the New York Public Service Commission which could have a material impact on the Customer's financial condition. Customer must take reasonable measures to obtain permission to disclose information related to a non-public investigation.

26.2.1.4 Material Change in Financial Status

A Customer shall inform the ISO of any material change in its financial status within five (5) business days, including but not limited to: (a) a downgrade of a long- or short-term debt rating by any ISO-approved rating agency; (b) placement on a negative credit watch by any ISO-approved rating agency; (c) a bankruptcy filing, insolvency, or a default under any financing

agreement; (d) resignation or termination of a key officer; (e) initiation of a lawsuit that could materially and adversely impact current or future financial performance; or (f) restatement of prior financial statements.

26.2.1.5 Change in Peak Load

A Load Serving Entity shall inform the ISO as soon as practicable if it expects its peak Load to increase by fifteen percent (15%) or more above its peak Load during the Prior Equivalent Capability Period.

26.2.1.6 Financial Statements

Customer shall keep on file with the ISO its most recent annual financial statements (including, but not limited to, balance sheet and income statement), which shall be submitted to the ISO annually within ten (10) days of such statements becoming available and within ninety (90) days of the end of the fiscal year of such Customer. If such financial statements are not audited, Customer shall submit with the financial statements a certification from an officer of the Customer, in a form acceptable to the ISO, certifying the accuracy of the financial statements.

If a Customer does not routinely prepare financial statements, Customer shall submit equivalent financial information annually, as required in the paragraph above, with a certification from an officer of the Customer certifying the accuracy of the financial information submitted, in forms acceptable to the ISO.

The ISO may grant an extension for the provision of the required financial information under this Section 26.2.1.6 upon a showing of good cause.

26.2.2 Customers Requesting Unsecured Credit

In addition to the reporting requirements in Section 26.2.1., above, a Customer requesting

Unsecured Credit, including a request for an Equivalency Rating, shall be required to comply with the reporting requirements of this Section 26.2.2.

26.2.2.1 Financial Statements

A Customer requesting Unsecured Credit shall provide to the ISO audited annual financial statements from the most recent three (3) years and its recent quarterly financial statement. Thereafter, the Customer shall provide audited annual financial statements to the ISO within ten (10) days of such statements becoming available and within ninety (90) days of the end of each fiscal year and shall provide quarterly financial statements to the ISO within sixty (60) days of the end of each quarter. The ISO may grant an extension for the provision of quarterly and annual financial statements upon a showing of good cause.

26.2.2.2 Publicly-Traded Customer

A publicly-traded Customer shall provide financial statements on Form 10-K and 10-Q, respectively. A publicly-traded Customer shall also provide Form 8-K reports within five (5) business days of their issuance. Information available on EDGAR shall be deemed provided by a Customer that directs the ISO to obtain it there.

26.2.2.3 Privately-Held Customer

A Customer that is not publicly-traded shall provide financial statements that include a balance sheet including a statement of stockholders' equity, an income statement, a statement of cash flow, notes to the financial statement, and an unqualified auditor's opinion.

26.2.2.4 Government Entities

Notwithstanding Section 26.2.2.1 of this Attachment K, government entities that do not normally prepare quarterly financial statements shall not be required to provide them to qualify

for Unsecured Credit.

26.3 Investment Grade Customers

26.3.1 Senior Long-Term Unsecured Debt Rating

A Customer shall be deemed an Investment Grade Customer if its senior long-term unsecured debt rating is BBB- or higher by Standard & Poor's or Fitch, or Baa3 or higher by Moody's. If a Customer has been rated by two of these agencies, the ISO shall use the lower of the two ratings. If a Customer is rated by all three of these rating agencies, and one rating agency differs in its rating of a Customer from the other two, the ISO shall use the matching ratings. If a Customer is rated differently by all three of these rating agencies, the ISO shall use the middle rating. A Customer that has not been rated by any of the three above-named rating agencies may use a rating from Dominion. Notwithstanding the above, a Customer with a senior long-term unsecured debt rating from any of the approved rating agencies below BBB- (or Baa3) shall be deemed to be a Non-Investment Grade Customer.

26.3.2 Issuer Rating

If a Customer does not have a senior long-term unsecured debt rating from Standard & Poor's, Fitch, Moody's or Dominion, the Customer shall nevertheless be deemed an Investment Grade Customer if it has an issuer rating of BBB or higher from Standard & Poor's, Fitch, or Dominion, or Baa2 or higher from Moody's.

A Customer that has a senior long-term unsecured debt rating from Standard & Poor's, Fitch, Moody's or Dominion shall not be permitted to substitute an issuer rating. The rules established in Section 26.3.1 of this Attachment K regarding conflicting ratings and the use of a Dominion rating shall apply to issuer ratings. Notwithstanding the above, a Customer with an issuer rating from any of the approved rating agencies below BBB (or Baa2) shall be deemed to be a Non-Investment Grade Customer.

26.3.3 Equivalency Rating

A Customer that has not received a senior long-term unsecured debt rating or an issuer rating from Standard & Poor's, Moody's, Fitch, or Dominion may request that the ISO assign it an Equivalency Rating. The ISO shall determine an Equivalency Rating using Moody's KMV RiskCalc™. A Customer with an Equivalency Rating of BBB or higher shall be deemed to be an Investment Grade Customer. The ISO shall review a Customer's Equivalency Rating at least once each quarter. A Customer may not use an Equivalency Rating in the event that it is rated by an ISO-approved rating agency.

26.4 Operating Requirement and Bidding Requirement

26.4.1 Purpose and Function

The Operating Requirement is a measure of a Customer's expected financial obligations to the ISO based on the nature and extent of that Customer's participation in ISO-Administered Markets. A Customer shall be required to allocate Unsecured Credit, where allowed, and/or provide collateral in an amount equal to or greater than its Operating Requirement. Upon a Customer's written request, the ISO will provide a written explanation for any changes in the Customer's Operating Requirement.

The Bidding Requirement is a measure of a Customer's potential financial obligation to the ISO based upon the bids that Customer seeks to submit in an ISO-administered TCC or ICAP auction. A Customer shall be required to allocate Unsecured Credit, where allowed, and/or provide collateral in an amount equal to or greater than its Bidding Requirement prior to submitting bids in an ISO-administered TCC or ICAP auction.

26.4.2 Calculation of Operating Requirement

The Operating Requirement shall be equal to the sum of (i) the Energy and Ancillary Services Component; (ii) the External Transaction Component; (iii) the UCAP Component; (iv) the TCC Component; (v) the WTSC Component; (vi) the Virtual Transaction Component; (vii) the Projected True-Up Exposure Component; and (viii) the Former RMR Generator Component, where:

26.4.2.1 Energy and Ancillary Services Component

The Energy and Ancillary Services Component shall be equal to the value calculated using the applicable formula below, subject to any adjustment the ISO may deem necessary in connection with the imposition of duties on electric energy under Schedule 22:

(a) For Customers without a prepayment agreement, the greater of either:

$$\frac{Basis\ Amount\ for\ Energy\ and\ Ancillary\ Services}{Days\ in\ Basis\ Month} * 16$$

- or -

$$\frac{Total\ Charges\ Incurred\ for\ Energy\ and\ Ancillary\ Services\ for\ Previous\ Ten\ (10) Days}{10} * 16$$

(b) For Customers that qualify for a prepayment agreement, subject to the ISO's credit analysis and approval, and execute a prepayment agreement in the form provided in Appendix K-1, the greater of either:

$$\frac{Basis\ Amount\ for\ Energy\ and\ Ancillary\ Services}{Days\ in\ Basis\ Month} * 3$$

-or-

$$\frac{Total\ Charges\ Incurred\ for\ Energy\ and\ Ancillary\ Services\ for\ Previous\ Ten\ (10) Days}{10} * 3$$

(c) For new Customers, the ISO shall determine a substitute for the Basis Amount for Energy and Ancillary Services for use in the appropriate formula above equal to:

$$EPL * 720 * AEP$$

where:

EPL = estimated peak Load for the Capability Period; and

AEP = average Energy and Ancillary Services price during the Prior Equivalent Capability Period after applying the Price Adjustment.

26.4.2.2 External Transaction Component

The External Transaction Component shall equal the sum of the Customer's (i) Import Credit Requirement, (ii) Export Credit Requirement, (iii) Wheels Through Credit Requirement, and (iv) the net amount owed to the ISO for the settled External Transaction Component Transactions.

26.4.2.2.1 Import Credit Requirement

For a given month, the Import Credit Requirement shall apply to any Customer that Bids to Import in the Day-Ahead Market ("DAM") unless (i) the Customer has at least 50 scheduled Day-Ahead Import Bids in the three-month period ending on the 15th day of the preceding month (or the six-month period ending on the 15th day of the preceding month if the Customer has fewer than 50 scheduled Day-Ahead Import Bids in the immediately preceding three-month period), and (ii) fewer than 25% of the MWhs of such scheduled Day-Ahead Import Bids were settled at a loss to the Customer.

The Import Credit Requirement shall equal the sum of the amounts calculated for each Bid in accordance with the appropriate formulas below:

(1) Upon submission of a DAM Import Bid until posting of the applicable DAM schedule/price.

The ISO will calculate the required credit support for pending DAM Import Bids for a market day three days prior to the DAM close for that market day. The ISO will calculate the required credit support for DAM Import Bids that are submitted after the commencement of the initial credit evaluation upon Bid submission. The ISO will categorize each Import Bid into one of the 33 Import Price Differential ("IPD") groups set forth in the IPD chart in Section 26.4.2.2.4 below, as

appropriate, based upon the season, weekday/weekend, holiday, and time-of-day of the Import Bid. For each Proxy Generator Bus, the amount of credit support required in $/MWh that applies to an Import Bid shall equal the 98th percentile level of the following: the hourly average Energy price calculated in the Real-Time Market at the location associated with the Import Bid, minus the Energy price calculated in the DAM at the same location and time, with the dataset used to perform this calculation consisting of all hours that are in the same IPD group as the hour to which the Import Bid applies in the previous one (1) year ending on the last day of the calendar month preceding the month to which the Import Bid applies and in the previous five (5) years ending on the last day of the calendar month preceding the month to which the Import Bid applies ("Import Price Differential"). The Import Price Differential will be calculated by applying a weight of 1/3 to the previous one (1) year ending on the last day of the calendar month preceding the month to which the Import Bid applies and a weight of 2/3 to the previous five (5) years ending on the last day of the calendar month preceding the month to which the Import Bid applies. If there is not sufficient historical price data at the location associated with the Import Bid to perform this calculation, then the ISO will use the historical price data from a location with like characteristics. The amount of credit support required in $/MWh shall not be less than $0/MWh.

The credit requirement for each Import Bid shall be calculated as follows:

$$Bid_{MWhB} * Max\ (IPD_{CS}, 0)$$

Where:

Bid_{MWhB} = the total quantity of MWhs that a Customer Bids to Import in a particular hour and at a particular location.

IPD_{CS} = the amount of credit support required, in $/MWh, for an Import Bid as described above, for the location associated with the Import Bid (or location with like characteristics, if applicable) and for the IPD group that contains the hour to which the Import Bid applies.

(2) Upon posting of the applicable DAM schedule/price until completion of the hour Bid in real-time for a DAM Import Bid.

The credit requirement for each Import Bid shall be calculated as follows:

$$SchBid_{MWhI} * Max(IPD_{CS}, 0)$$

Where:

$SchBid_{MWhI}$ = the total quantity of MWhs that is scheduled in the DAM in a particular hour and at a particular location as a result of the Customer's Import Bid.

IPD_{CS} = the amount of credit support required, in $/MWh, for an Import Bid as described above, for the location associated with the Import Bid (or location with like characteristics, if applicable) and for the IPD group that contains the hour to which the Import Bid applies.

(3) Upon completion of the hour Bid in real-time for a DAM Import Bid until the net amount owed to the ISO is determined for settled External Transactions.

The credit requirement for each Import Bid shall be calculated as follows:

$$Max((BalPay_{\$} - DAMPay_{\$}), 0)$$

Where:

$BalPay_{\$}$ = $(SchBid_{MWhI} - Actual_{MWhI}) * RT\ LBMP_I$

$DAMPay_{\$}$ = $SchBid_{MWhI} * DAM\ LBMP_I$

$SchBid_{MWhI}$ = the total quantity of MWhs that is scheduled in the DAM in a particular hour at a particular location as a result of the Customer's Import Bid.

$Actual_{MWhI}$ = the total quantity of MWhs that is scheduled in real-time associated with the Customer's Import Bid in a particular hour and at a particular location for the hour completed.

$DAM\ LBMP_I$ = the Day-Ahead LBMP in a particular hour and at a particular location associated with the Customer's Import Bid.

$RT\ LBMP_I$ = the Real-Time LBMP in a particular hour and at a particular location associated with the Customer's Import Bid.

26.4.2.2.2 Export Credit Requirement

The Export Credit Requirement shall apply to any Customer that Bids to Export from the DAM or Hour-Ahead Market ("HAM").

The Export Credit Requirement shall equal the sum of the amounts calculated for each Bid in accordance with the appropriate formulas below:

(1) Upon submission of a DAM Export Bid until posting of the applicable DAM schedule/price.

The ISO will calculate the required credit support for pending DAM Export Bids for a market day three days prior to the DAM market close for that market day. The ISO will calculate the required credit support for DAM Export Bids that are submitted after the commencement of the initial credit evaluation upon Bid submission. The ISO will categorize each Export Bid into one of the 28 Export Price Differential ("EPD") groups set forth in the EPD chart in Section 26.4.2.2.4 below, as appropriate, based upon the season, weekday/weekend, holiday, and time-of-day of the Export Bid. For each Proxy Generator Bus, the amount of credit support required in $/MWh that applies to an Export Bid shall equal the 97th percentile level of the following: the Energy price calculated in the DAM at the location associated with the Export Bid, minus the hourly average Energy price calculated in the Real-Time Market at the same location and time, with the dataset used to perform this calculation consisting of all hours that are in the same EPD group as the hour to which the Export Bid applies in the previous one (1) year ending on the last day of the calendar month preceding the month to which

the Export Bid applies and in the previous five (5) years ending on the last day of the calendar month preceding the month to which the Export Bid applies ("Export Price Differential"). The Export Price Differential will be calculated by applying a weight of 1/3 to the previous one (1) year ending on the last day of the calendar month preceding the month to which the Export Bid applies and a weight of 2/3 to the previous five (5) years ending on the last day of the calendar month preceding the month to which the Export Bid applies. If there is not sufficient historical price data at the location associated with the Export Bid to perform this calculation, then the ISO will use the historical price data from a location with like characteristics. The amount of credit support required in $/MWh shall not be less than $0/MWh.

The credit requirement for all DAM Export Bids with the same hour/date and location shall be calculated as follows:

$$(Max((Max_N(Bid_{MWh} * Bid_{\$E})),(BidMax_{MWhB} * EPD_{CS})))$$

Where:

Bid_{MWh}	=	the total quantity of MWhs that a Customer Bids to Export in the DAM in a particular hour and at a particular location at or below each Bid Price.
$Bid_{\$E}$	=	the Bid Price in $/MWh at which the Customer Bids to purchase the Bid_{MWh} of Exports in a particular hour and at a particular location.
N	=	the set of hourly Export Bid Prices in a particular hour and at a particular location.
$BidMax_{MWhB}$	=	the total quantity of MWhs that a Customer Bids to Export in the DAM in a particular hour and at a particular location.
EPD_{CS}	=	the amount of credit support required, in $/MWh, for an Export Bid as described above, for the location associated with the Export Bid (or location with like characteristics, if applicable) and for the EPD group that contains the hour to which the Export Bid applies.

(2) Upon posting of the applicable DAM schedule/price until completion of hour Bid in real-time for a DAM Export Bid.

The credit requirement for each Export Bid shall be calculated as follows:

$$(SchBid_{MWhE} * (Max(EPD_{CS}, DAM\ LBMP_{E})))$$

Where:

$SchBid_{MWhE}$ = the total quantity of MWhs that is scheduled in the DAM in a particular hour at a particular location as a result of the Customer's Export Bid.

EPD_{CS} = the amount of credit support required, in $/MWh, for an Export Bid as described above, for the location associated with the Export Bid (or location with like characteristics, if applicable) and for the EPD group that contains the hour to which the Export Bid applies.

DAM $LBMP_{E}$ = the Day-Ahead LBMP in a particular hour and at a particular location associated with the Customer's Export Bid.

(3) From submission of a HAM Export Bid until completion of the hour Bid in real-time.

i. Non-CTS Interface Bids to Export .

The ISO will calculate the required credit support for pending HAM non-CTS Interface Bids to Export for a market day three days prior to the DAM close for that market day. The ISO will calculate the required credit support for HAM non-CTS Interface Bids to Export that are submitted after the commencement of the initial credit evaluation upon Bid submission. The amount of credit support required in $/MWh that applies to HAM non-CTS Interface Bids Export in the same hour/date and at the same location shall equal the maximum amount of the payment potentially due to the ISO based on the MWhs of Exports Bid for purchase at each bid price in a particular hour and at a particular location.

The credit requirement for all HAM non-CTS Interface Bids to Export with the same hour/date and location shall be calculated as follows:

$$(Max_N((Max(Bid_{MWhE}, 0)) * Bid_{\$E}))$$

Where:

Bid_{MWhE}	=	the total quantity of MWhs that a Customer Bids to Export in the HAM in a particular hour and at a particular location at or below each bid price minus the MWhs of Exports scheduled in the DAM in the same hour at the same location.
$Bid_{\$E}$	=	the bid price in $/MWh at which the Customer Bids to purchase the Bid_{MWhE} of Exports in a particular hour and at a particular location.
N	=	the set of hourly Export bid prices in a particular hour and at a particular location.

ii. CTS Interface Bids to Export.

For CTS Interface Bids to Export credit support will be calculated at HAM close.

The amount of credit support required in $/MWh that applies to such bid shall equal the sum of the time-weighted hourly RTC price for each of the 15-minute intervals within the bid hour, not to be less than zero.

The credit requirement for each CTS Interface Bid to Export shall be calculated as follows:

$$Max\left(\sum_N \left(RTC_{\$/MWhcts} * Bid_{MWhscts} * Hourly\ Weight\right), 0\right)$$

Where:

N	=	each 15-minute interval within the bid hour.
$RTC_{\$/MWhcts}$	=	most recently available RTC price for N in $/MWh at the location associated with the CTS Interface Bid to Export
$Bid_{MWhscts}$	=	the total quantity of MWhs in a Customer's CTS Interface Bid to Export for N in a particular hour and at a particular location minus the MWhs of Exports scheduled in the DAM in same hour at the same location.
Hourly Weight	=	0.25

(4) Upon completion of the hour Bid in real-time for an Export Bid until the net amount owed to the ISO is determined for settled External Transactions.

The amount of credit support required will equal the sum of the Day-Ahead Credit Calculation and Real-Time Credit Calculation for each completed hour.

The credit requirement for each Export Bid shall be calculated as follows:

Day-Ahead Credit Calculation + Real-Time Credit Calculation

The Day-Ahead Credit Calculation only applies to DAM Export Bids and the Real-Time Credit Calculation applies to all HAM Export Bids including HAM Bids associated with a DAM Bid.

Where:

Day-Ahead Credit Calculation = Max (Adjusted Export Day-Ahead Credit Calculation, 0)

Adjusted Export Day-Ahead Credit Calculation = the credit requirement calculated in accordance with section 26.4.2.2.2(2) minus the Balancing Payment.

$$Balancing\ Payment = Max((SchBid_{MWhE} - Actual_{MWhE}),0) * RT\ LBMP_E$$

$SchBid_{MWhE}$ = the total quantity of MWhs that is scheduled in the DAM in a particular hour and at a particular location as a result of the Customer's Export Bid.

$Actual_{MWhE}$ = the total quantity of MWhs that is scheduled in real-time associated with the Customer's Export Bid in a particular hour and at a particular location for the hour completed.

$RT\ LBMP_E$ = the Real-Time LBMP in a particular hour and at a particular location associated with the Customer's Export Bid.

$$Real\text{-}Time\ Credit\ Calculation = Max((Max((Actual_{MWhE} - SchBid_{MWhE}),0) * RT\ LBMP_E),0)$$

$Actual_{MWhE}$ = the total quantity of MWhs that is scheduled in real-time associated with the Customer's Export Bid in a particular hour and at a particular location for the hour completed.

$SchBid_{MWhE}$ = the total quantity of MWhs that is scheduled in the DAM in a particular hour and at a particular location as a result of the Customer's Export Bid.

$RT\ LBMP_E$ = the Real-Time LBMP in a particular hour and at a particular location associated with the Customer's Export Bid.

26.4.2.2.3 Wheels Through Credit Requirement

The Wheels Through Credit Requirement shall apply to any Customer that Bids to Wheel Through in the DAM or HAM.

The Wheels Through Credit Requirement shall equal the sum of the amounts calculated for each Bid in accordance with the appropriate formulas below:

(1) Upon submission of a DAM Wheels Through Bid until posting of the applicable DAM schedule/price.

The ISO will calculate the required credit support for pending DAM Wheels Through Bids for a market day three days prior to the DAM close for that market day. The ISO will calculate the required credit support for DAM Wheels Through Bids that are submitted after the commencement of the initial credit evaluation upon Bid submission. The amount of credit support required in $/MWh that applies to the DAM Wheels Through Bid shall equal the maximum payment potentially due to the ISO based on the Customer's Bid Prices on the Bid curve. The credit requirement for each Wheels Through Bid shall be calculated as follows:

$$Max\left(Max_N\left(BidPt_{MWhN} * Bid\$_{\$/MWhN}\right), 0\right)$$

Where:

N = each Bid Price on the Bid curve.

$BidPt_{MWhN}$ = the MWhs associated with the Bid Price on the Bid curve.

$Bid\$_{\$/MWhN}$ = the amount that the customer is willing to pay for congestion in $/MWh on the Bid curve associated with the Customer's Wheels Through Bid.

(2) Upon posting of the applicable Wheels Through DAM schedule/price until completion of the hour Bid in real-time.

The credit requirement for each DAM Wheels Through Bid shall be calculated as follows:

$$Max(SchBid_{MWhW} * (DAM\ LBMP_{POW} - DAM\ LBMP_{POI}), 0)$$

Where:

$SchBid_{MWhW}$ = the total quantity of MWhs scheduled in the DAM as a result of the Customer's Bid to schedule Wheels Through.

DAM $LBMP_{POI}$ = the Day-Ahead LBMP in the hour and at the Point of Injection associated with the Wheels Through Bid.

DAM $LBMP_{POW}$ = the Day-Ahead LBMP in the hour and at the Point of Withdrawal associated with the Wheels Through Bid.

(3) Upon creation of a HAM Wheels Through Bid until the completion of the hour Bid in real-time.

The ISO will calculate the required credit support for pending HAM Wheels Through Bids for a market day three days prior to the DAM close for that market day. The ISO will calculate the required credit support for HAM Wheels Through Bids that are submitted after the commencement of the initial credit evaluation upon Bid submission. The amount of credit support required in $/MWh that applies to HAM Wheels Through Bid shall equal the price of the maximum value of exposure based on bid prices on the Bid curve.

The credit requirement for each Wheels Through Bid shall be calculated as follows:

$$Max\left(Max_N\left(Max(BidPt_{MWhW},0) * Bid\$_{\$/MWhN}\right),0\right)$$

Where:

N = each bid price on the Bid curve.

$BidPt_{MWhW}$ = the MWhs associated with the bid price on the Bid curve minus the MWhs of the DAM Bid with same hour/date, location and Bid transaction ID.

$Bid\$_{\$/MWhN}$ = the amount that the customer is willing to pay for congestion in $/MWh on the Bid curve associated with the Customer's Wheels Through Bid.

(4) Upon completion of the hour Bid in real-time for a Wheels Through Bid until the net amount owed to the ISO is determined for settled External Transactions.

The amount of credit support required will equal the sum of the Day-Ahead Credit Calculation and Real-Time Credit Calculation for each completed hour.

The credit requirement for each Wheels Through Bid shall be calculated as follows:

Day-Ahead Credit Calculation + Real-Time Credit Calculation

The Day-Ahead Credit Calculation only applies to DAM Wheels Through Bids and the Real-Time Credit Calculation applies to all HAM Wheels Through Bids including HAM Bids associated with a DAM Bid.

Where:

Day-Ahead Credit Calculation = Max (Adjusted Wheels Through Day-Ahead Credit Calculation, 0)

Adjusted Wheels Through Day-Ahead Credit Calculation = the credit requirement calculated in section 26.4.2.2.3(2) minus the Balancing Payment.

$$Balancing\ Payment = Max((SchBid_{MWhW} - Actual_{MWhW}),0) * (RT\ LBMP_{POW} - RT\ LBMP_{POI})$$

$SchBid_{MWhW}$ = the total quantity of MWhs that is scheduled in the DAM as a result of the Customer's Wheels Through Bid.

$Actual_{MWhW}$ = the total quantity of MWhs that is scheduled in real-time associated with the Customer's Wheels Through Bid for the hour completed.

$RT\ LBMP_{POI}$ = the Real-Time LBMP in the hour and at the Point of Injection associated with the Wheels Through Bid.

$RT\ LBMP_{POW}$ = the Real-Time LBMP in the hour and at the Point of Withdrawal associated with the Wheels Through Bid.

$$Real\text{-}Time\ Credit\ Calculation = Max(Max((Actual_{MWhW} - SchBid_{MWhW}),0) * (RT\ LBMP_{POW} - RT\ LBMP_{POI}),0)$$

$SchBid_{MWhW}$ = the total quantity of MWhs that is scheduled in the DAM as a result of the Customer's Bid to Wheel Through Energy.

$Actual_{MWhW}$ = the total quantity of MWhs that is scheduled in real-time associated with the Customer's Wheels Through Bid for the hour completed.

$RT\ LBMP_{POI}$ = the Real-Time LBMP in the hour and at the Point of Injection associated with the Wheels Through Bid.

$RT\ LBMP_{POW}$ = the Real-Time LBMP in the hour and at the Point of Withdrawal associated with the Wheels Through Bid.

26.4.2.2. 4 Calculation of Price Differentials

Import Price Differential (IPD) Groups

Summer	IPD Group For Each Proxy Generator Bus
HB07–09	IPD-1
HB10–12	IPD-2
HB13–17	IPD-3
HB18	IPD-4
HB19-20	IPD-5
HB21-22	IPD-6
Weekend/ Holiday (HB07–08)	IPD-7
Weekend/ Holiday (HB09–12)	IPD-8
Weekend/ Holiday (HB13–14)	IPD-9
Weekend/ Holiday (HB15–16)	IPD-10
Weekend/ Holiday (HB17–18)	IPD-11
Weekend/ Holiday (HB19–22)	IPD-12
Night (HB00,23)	IPD-13
Night (HB01-06)	IPD-14
Winter	
HB08–09	IPD-15
HB10–12	IPD-16
HB13–15	IPD-17

HB16-17	IPD-18
HB18-20	IPD-19
HB21-22	IPD-20
Weekend/ Holiday (HB16–20)	IPD-21
Weekend/ Holiday (Other HB08-22)	IPD-22
Night (HB00,01,23)	IPD-23
Night (HB02-05)	IPD-24
Night (HB06-07)	IPD-25
Rest-of-Year	
HB07–10	IPD-26
HB11–14	IPD-27
HB15–19	IPD-28
HB20-22	IPD-29
Weekend/ Holiday (HB17–20)	IPD-30
Weekend/ Holiday (Other HB07-22)	IPD-31
Night (HB00,06,23)	IPD-32
Night (HB01-05)	IPD-33

Where:

Summer	=	May, June, July, and August
Winter	=	December, January, and February
Rest-of-Year	=	March, April, September, October, and November
Weekend	=	Saturday and Sunday
Holiday	=	NERC-defined holidays
HB	=	Hour Beginning x:00

Export Price Differential (EPD) Groups

Summer	EPD Group For Each Proxy Generator Bus
HB07–09	EPD-1
HB10–11	EPD-2
HB12-13	EPD-3

HB14-17	EPD-4
HB18-20	EPD-5
HB21-22	EPD-6
Weekend/ Holiday (HB13-19)	EPD-7
Weekend/ Holiday (Other HB07-22)	EPD-8
Night (HB00,23)	EPD-9
Night (HB01-06)	EPD-10
Winter	
HB07–09	EPD-11
HB10–12	EPD-12
HB13–15	EPD-13
HB16-17	EPD-14
HB18-20	EPD-15
HB21-22	EPD-16
Weekend/ Holiday (HB16–20)	EPD-17
Weekend/ Holiday (Other HB07-22)	EPD-18
Night (HB02-04)	EPD-19
Night (Other HB23-06)	EPD-20
Rest-of-Year	
HB07–10	EPD-21
HB11–14	EPD-22
HB15–19	EPD-23
HB20-22	EPD-24
Weekend/ Holiday (HB17–20)	EPD-25
Weekend/ Holiday (Other HB07-22)	EPD-26
Night (HB00,06,23)	EPD-27
Night (HB01-05)	EPD-28

Where:

Summer	=	May, June, July, and August
Winter	=	December, January, and February
Rest-of-Year	=	March, April, September, October, and November
Weekend	=	Saturday and Sunday
Holiday	=	NERC-defined holidays
HB	=	Hour Beginning x:00

26.4.2.3 UCAP Component

The UCAP Component shall be equal to the total of all amounts then-owed (billed and unbilled) for UCAP purchased in the ISO-administered markets.

26.4.2.4 TCC Component

The TCC Component shall be equal to the amount calculated in accordance with Section 26.4.2.4.1; *provided however*, that upon initial award of a TCC until the ISO receives payment for the TCC, the ISO will hold the greater of the payment obligation for the TCC or the credit requirement for the TCC calculated in accordance with this Section 26.4.2.4.

26.4.2.4.1 Auction TCC Holding Requirement

This Section 26.4.2.4.1 applies to all TCCs regardless of whether awarded in the Centralized TCC Auction and Balance-of-Period Auction or otherwise; provided, however, for purposes of this Section 26.4.2.4, Incremental TCCs and Grandfathered TCCs shall be considered as a series of one-year TCCs for the entire duration that such TCCs remain valid.

The credit requirement pursuant to this Section 26.4.2.4.1 shall equal the sum of the amounts calculated in accordance with the appropriate per TCC term-based formulas listed below. The ISO will not impose a credit requirement on TCCs that have been sold by a Market Participant in the Centralized TCC Auction or Balance-of-Period Auction.

26.4.2.4.1.1 Two-Year TCCs:

(1) upon initial award of a two-year TCC (including a Fixed Price TCC with a two-year duration) until completion of the final round of the current two-year Sub-Auction, the sum of the first year and second year amounts, which will be calculated as follows:

First Year:

the amount calculated in accordance with the one-year TCC formula set forth in Section 26.4.2.4.1.5 below

where:

P_{ijt} = market clearing price of a one-year TCC in the final round of the one-year Sub-Auction in the prior Capability Period Centralized TCC Auction with the same POI and POW combination as the two-year TCC.

Second Year:

the amount calculated in accordance with the one-year TCC formula set forth in Section 26.4.2.4.1.5 below

where:

P_{ijt} = market clearing price of that two-year TCC (or, in the case of a Fixed Price TCC, a two-year TCC with the same POI and POW combination as the Fixed Price TCC) minus the market clearing price of a one-year TCC in the final round of the one-year Sub-Auction in the prior Capability Period Centralized TCC Auction with the same POI and POW combination as the two-year TCC

(2) upon completion of the final round of the current two-year Sub-Auction until completion of the final round of the current one-year Sub-Auction, the sum of the first year and second year amounts, which will be calculated as follows:

First Year:

the amount calculated in accordance with the one-year TCC formula set forth in Section 26.4.2.4.1.5 below

where:

P_{ijt} = market clearing price of a one-year TCC in the final round of the one-year Sub-Auction in the prior Capability Period Centralized TCC Auction with the same POI and POW combination as the two-year TCC

Second Year:

the amount calculated in accordance with the one-year TCC formula set forth in Section 26.4.2.4.1.5 below

where:

P_{ijt} = market clearing price of a two-year TCC in the final round of the current two-year Sub-Auction with the same POI and POW combination as the two-year TCC minus the market clearing price of a one-year TCC in the final round of the one-year Sub-Auction in the prior Capability Period Centralized TCC Auction with the same POI and POW combination as the two-year TCC

(3) upon completion of the final round of the current one-year Sub-Auction until completion of the Balance-of-Period Auction for the first month of the two-year TCC, the sum of the first year and second year amounts, which will be calculated as follows:

First Year:

the amount calculated in accordance with the one-year TCC formula set forth in Section 26.4.2.4.1.5 below

where:

P_{ijt} = market clearing price of a one-year TCC in the final round of the current one-year Sub-Auction with the same POI and POW combination as the two-year TCC

Second Year:

the amount calculated in accordance with the one-year TCC formula set forth in Section 26.4.2.4.1.5 below

where:

P_{ijt} = market clearing price of a two-year TCC in the final round of the current two-year Sub-Auction with the same POI and POW combination as the two-year TCC minus the market clearing price of a one-year TCC in the final round of the current one-year Sub-Auction with the same POI and POW combination as the two-year TCC

(4) upon completion of the Balance-of-Period Auction for the first month of the two-year TCC until completion of the final round of the six-month Sub-Auction in the next Centralized TCC Auction, the sum of the first year and second year amounts, which will be calculated as follows:

First Year:

the amount calculated in accordance with the appropriate Balance-of-Period Auction holding requirement formulas set forth in Section 26.4.2.4.1.6 below

Second Year:

the amount calculated in accordance with the one-year TCC formula set forth in Section 26.4.2.4.1.5 below

where:

Pijt = market clearing price of a two-year TCC in the final round of the two-year Sub-Auction in which the TCC was purchased (or, in the case of a Fixed Price TCC, the final round of the two-year Sub-Auction of the Centralized TCC Auction in which the six-month Sub-Auction made transmission capacity available to support the sale of TCCs for the first Capability Period in which the applicable Fixed Price TCC would be valid) with the same POI and POW combination as the two-year TCC minus the market clearing price of a one-year TCC in the final round of the one-year Sub-Auction that directly followed the two-year Sub-Auction in which the TCC was purchased (or, in the case of a Fixed Price TCC, the two-year Sub-Auction of the Centralized TCC Auction in which the six-month Sub-Auction made transmission capacity available to support the sale of TCCs for the first Capability Period in which the applicable Fixed Price TCC would be valid) with the same POI and POW combination as the two-year TCC

(5) upon completion of the final round of the six-month Sub-Auction for the final six months of the first year of the two-year TCC until completion of the Balance-of-Period Auction immediately preceding the final six months of the first year of the two-year TCC, the sum of the first year and second year amounts, which will be calculated as follows:

First Year:

the amount calculated in accordance with the six-month TCC formula set forth in Section 26.4.2.4.1.5 below

where:

Pijt = market clearing price of a six-month TCC in the final round of the six-month Sub-Auction with the same POI and POW combination as the two-year TCC

Second Year:

the amount calculated in accordance with the one-year TCC formula set forth in Section 26.4.2.4.1.5 below

where:

Pijt = market clearing price of a one-year TCC in the single round one-year Sub-Auction for TCCs valid during the same period as the second year of the two-year TCC in the next Centralized TCC Auction after the Centralized TCC Auction in which the two-year TCC was initially awarded and having the same POI and POW combination as the two-year TCC

(6) upon completion of the Balance-of-Period Auction immediately preceding the final six months of the first year of the two-year TCC until ISO receipt of payment for the second year of the two-year TCC, the sum of the first year and second year amounts, which will be calculated as follows:

First Year:

the amount calculated in accordance with the appropriate Balance-of-Period TCC Auction holding requirement formula set forth in Section 26.4.2.4.1.6 below

Second Year:

the amount calculated in accordance with the appropriate one-year TCC Auction holding requirement formula set forth in Section 26.4.2.4.1.5 below

where:

Pijt = market clearing price of a one-year TCC in the single round one-year Sub-Auction for TCCs valid during the same period as the second year of the two-year TCC in the next Centralized TCC Auction after the Centralized TCC Auction in which the two-year TCC was initially awarded and having the same POI and POW combination as the two-year TCC

(7) upon ISO receipt of payment for the second year of the two-year TCC until completion of the final round of the one-year Sub-Auction for the second year of the two-year TCC, the sum of the first year and second year amounts, which will be calculated as follows:

First Year:

the amount calculated in accordance with the appropriate Balance-of-Period Auction holding requirement formula set forth in Section 26.4.2.4.1.6 below

Second Year:

the amount calculated in accordance with the one-year TCC formula set forth in Section 26.4.2.4.1.5 below

where:

P_{ijt} = market clearing price of a one-year TCC in the single round one-year Sub-Auction for TCCs valid during the same period as the second year of the two-year TCC in the next Centralized TCC Auction after the Centralized TCC Auction in which the two-year TCC was initially awarded and having the same POI and POW combination as the two-year TCC

(8) upon completion of the final round of the one-year Sub-Auction for the second year of the two-year TCC until completion of the Balance-of-Period Auction for the first month of the second year of the two-year TCC, the sum of the first year and second year amounts, which will be calculated as follows::

First Year:

the amount calculated in accordance with the appropriate Balance-of-Period Auction holding requirement formula set forth in Section 26.4.2.4.1.6 below

Second Year:

the amount calculated in accordance with the one-year TCC formula set forth in Section 26.4.2.4.1.5 below

where:

P_{ijt} = market clearing price of a one-year TCC in the final round of the most recently completed one-year Sub-Auction with the same POI and POW combination as the two-year TCC

(9) upon completion of the Balance-of-Period Auction for the first month of the second year of the two-year TCC until completion of the final round of the six-month Sub-Auction for the final six months of the two-year TCC, the sum of the first year and second year amounts, which will be calculated as follows:

First Year:

the amount calculated in accordance with the appropriate Balance-of-Period Auction holding requirement formula set forth in Section 26.4.2.4.1.6 below

Second Year:

the amount calculated in accordance with the appropriate Balance-of-Period Auction holding requirement formula set forth in Section 26.4.2.4.1.6 below

(10) upon completion of the final round of the six-month Sub-Auction for the final six months of the two-year TCC until completion of the Balance-of-Period Auction immediately preceding the final six months of the two-year TCC:

the amount calculated in accordance with the six-month TCC formula set forth in Section 26.4.2.4.1.5 below

where:

P_{ijt} = market clearing price of a six-month TCC in the final round of the most recently completed six-month Sub-Auction with the same POI and POW combination as the two-year TCC

(11) upon completion of the Balance-of-Period Auction for the first month of the final six months of a two-year TCC:

the amount calculated in accordance with the Balance-of-Period TCC formulas set forth in Section 26.4.2.4.1.5 below

26.4.2.4.1.2 One-Year TCCs:

(1) upon initial award of a one-year TCC (including a Fixed Price TCC with a one-year duration, an Incremental TCC, or a Grandfathered TCC) until completion of the final round of the current one-year Sub-Auction:

the amount calculated in accordance with the one-year TCC formula set forth in Section 26.4.2.4.1.5 below

(2) upon completion of the final round of the current one-year Sub-Auction until completion of the Balance-of-Period Auction for the first month of the one-year TCC:

the amount calculated in accordance with the one-year TCC formula set forth in Section 26.4.2.4.1.5 below

where:

P_{ijt} = market clearing price of a one-year TCC in the final round of the current one-year Sub-Auction with the same POI and POW combination as the one-year TCC

(3) upon completion of the Balance-of-Period Auction for the first month of the one-year TCC (including a Fixed Price TCC with a one-year duration, an Incremental TCC, or a Grandfathered TCC) until completion of the final round of the six month Sub-Auction in the next Centralized TCC Auction:

the amount calculated in accordance with the appropriate Balance-of-Period Auction holding requirement formula set forth in Section 26.4.2.4.1.6 below

(4) upon completion of the final round of the six-month Sub-Auction for the final six months of a one-year TCC (including a Fixed Price TCC with a one-year duration, an Incremental TCC, or a Grandfathered TCC) until completion of the Balance-of-Period Auction immediately preceding the final six months of a one-

year TCC (including a Fixed Price TCC with a one-year duration, an Incremental TCC, or a Grandfathered TCC):

the amount calculated in accordance with the six-month TCC formula set forth in Section 26.4.2.4.1.5 below

where:

P_{ijt} = market clearing price of a six-month TCC in the final round of the most recently completed six-month Sub-Auction with the same POI and POW combination as the one-year TCC

(5) upon completion of the Balance-of-Period Auction for the first month of the final six months of a one-year TCC:

the amount calculated in accordance with the appropriate Balance-of-Period Auction holding requirement formula set forth in Section 26.4.2.4.1.6 below

26.4.2.4.1.3 Six-Month TCCs:

(1) upon initial award of a six-month TCC (including an ETCNL TCC, or a RCRR TCC) until completion of the final round of the current six-month Sub-Auction:

the amount calculated in accordance with the six-month TCC formula set forth in Section 26.4.2.4.1.5 below

(2) upon completion of the final round of the current six-month Sub-Auction until completion of the Balance-of-Period Auction for the first month of a six-month TCC:

the amount calculated in accordance with the six-month TCC formula set forth in Section 26.4.2.4.1.5 below

where:

P_{ijt} = market clearing price of a six-month TCC in the final round of the current six-month Sub-Auction with the same POI and POW combination as the six-month TCC

(3) upon completion of the Balance-of-Period Auction for the first month of a six-month TCC:

the amount calculated in accordance with the Balance-of-Period Auction formula set forth in Section 26.4.2.4.1.6.1 below

26.4.2.4.1.4 One-Month TCCs:

upon initial award of a one-month TCC:

the amount calculated in accordance with the Balance-of-Period TCC Auction holding requirement formula set forth in Section 26.4.2.4.1.6.1 below

26.4.2.4.1.5 Centralized TCC Auction – Holding Requirement Formulas:

for one-year TCCs, representing a 5% probability curve:

$$+1.909\sqrt{e^{10.9729 + .6514\left(ln\left(|P_{ijt}| + e\right)\right) + .6633 * Zone\ J + 1.1607 * Zone\ K}} - 1\ P_{ijt}$$

for six-month TCCs, representing a 3% probability curve:

$$+2.565\sqrt{e^{11.6866 + .4749\left(ln\left(|P_{ijt}| + e\right)\right) + .4856 * Zone\ J + .8498 * Zone\ K - .0373\ Summer}} - 1\ P_{\boldsymbol{ijt}}$$

where:

P_{ijt} = market clearing price of i to j TCC in round t of the auction in which the TCC was purchased (or, in the case of an ETCNL TCC or a RCRR TCC, the auction in which the six-month Sub-Auction made transmission capacity available to support the sale of TCCs for the Capability Period in which the applicable ETCNL TCC or RCRR TCC would be valid);

Zone J = 1 if TCC sources or sinks but not both in Zone J, zero otherwise;

Zone K = 1 if TCC sources or sinks but not both in Zone K and does not source or sink in Zone J, 0 otherwise;

Summer = 1 for six-month TCCs sold in the spring auction, 0 otherwise; and

Further, when calculating "Pijt" in Section 26.4.2.4.1, in the event there is no market clearing price for a two-year, one-year, or six-month TCC in the appropriate prior Capability Period Centralized TCC Auction with the same POI and POW combination as the awarded two-year, one-year, or six-month TCC, as appropriate, then the market clearing price shall equal a proxy price, assigned by the ISO, for a TCC with like characteristics.

Further, the NYISO may adjust any of the Zone K multipliers in Section 26.4.2.4.1 if, for TCCs of the same duration, the percentage ratio between collateral and congestion rents for Zone K TCCs deviates from the percentage ratio for Zone J TCCs by more than ten percent (10.0%).

26.4.2.4.1.6 Balance-of-Period Auction – Holding Requirement Formulas:

During the Balance-of-Period Auction: (a) a TCC awarded in the Centralized TCC Auction (or the remaining segments of a TCC awarded in a prior Centralized TCC Auction); or (b) a Fixed Price TCC, an Incremental TCC, a Grandfathered TCC, an ETCNL TCC, or a RCRR TCC, valid during the period covered by the Balance-of-Period Auction is segmented, as appropriate, into (i) a monthly segment, corresponding to the months within the current Capability Period encompassed by the remaining duration of the TCC (or, in the case of an Incremental TCC or a Grandfathered TCC, the remaining duration of the assumed duration of the TCC for purposes of this Section 26.4), (ii) a future six-month segment, corresponding to months within the next Capability Period encompassed by the remaining duration of the TCC (or, in the case of an Incremental TCC or a Grandfathered TCC, the remaining duration of the assumed duration of the TCC for purposes of this Section 26.4), and (iii) a one-year segment, corresponding to all months after the Capability Period associated with the future six-month

segment encompassed by the remaining duration of the TCC (or, in the case of an Incremental TCC or a Grandfathered TCC, the remaining duration of the assumed duration of the TCC for purposes of this Section 26.4), such that the sum of segments (i), (ii), and (iii) covers the entire remaining duration of the TCC (or, in the case of an Incremental TCC or a Grandfathered TCC, the remaining duration of the assumed duration of the TCC for purposes of this Section 26.4). The credit holding requirement for the monthly segments and the future six-month segment are calculated in accordance with the formulas below. The credit holding requirement for the one-year segment is calculated in accordance with formulas for determining the credit holding requirement for the second year of a two-year TCC as described in Section 26.4.2.4.1.1 above; provided, however, that in the case of a Historic Fixed Price TCC for which less than twelve months are assigned to the one-year segment, the applicable Sub-Auctions from which the market-clearing price (P_{ijt}) used for the formulas described in Section 26.4.2.4.1.1 shall be the most recently completed two-year Sub-Auction prior to the effective date of that Historic Fixed Price TCC and the one-year Sub-Auction that immediately followed such two-year Sub-Auction. The credit holding requirement calculated for each segment shall be determined based on the number of months that are assigned to each segment for the remaining duration of a given TCC.

26.4.2.4.1.6.1 Monthly Segment

Monthly Segment ($) = [(Monthly Margin ($) ×Monthly Index Ratio×Monthly Factor) −TCC Price ($)]×MWs

where:

Monthly Margin is calculated based on a methodology approved by Market Participants and posted to the ISO's website

Monthly Index Ratio as determined from time to time by the ISO based on historical data and a methodology approved by Market Participants and posted to the ISO's website

Monthly Factor as determined from time to time by the ISO based on historical data and a methodology approved by Market Participants and posted to the ISO's website

TCC Price is the market clearing price for the respective Capability Period month in the most recent Balance-of-Period Auction

MWs is the number of awarded TCC MWs

26.4.2.4.1.6.2 Future Six-Month Segment

Future Six-Month Segment ($) = (Six-Month Margin ($)−TCC Price ($))×MWs

where:

Six-Month Margin is calculated based on a methodology approved by Market Participants and posted on the ISO's website

TCC Price is the market clearing price, using the same POI/POW combination, resulting from the

(1) Market clearing price from the final round of the most recent one-year TCC Sub-Auction, less the

(2) Market clearing price from the second round of the most recent six-month TCC Sub-Auction

MWs is the number of awarded TCC MWs

26.4.2.5 WTSC Component

The WTSC Component shall be equal to the greater of either:

$$\frac{Greatest\ Amount\ Owed\ for\ WTSC\ During\ Any\ Single\ Month\ in\ the\ Prior\ Equivalent\ Capability\ Period}{Days\ in\ Month} * 50$$

- or –

$$\frac{Total\ Charges\ Incurred\ for\ WTSC\ Based\ Upon\ the\ Most\ Recent\ Monthly\ Data\ Provided\ by\ the\ Transmission\ Owner}{Days\ in\ Month} * 50$$

26.4.2.6 Virtual Transaction Component

The Virtual Transaction Component shall be equal to the sum of the Customer's (i) Virtual Supply credit requirement ("VSCR") for all outstanding Virtual Supply Bids, plus (ii) Virtual Load credit requirement ("VLCR") for all outstanding Virtual Load Bids, plus (iii) net amount owed to the ISO for settled Virtual Transactions.

Where:

VSCR = $\sum(VSG_{MWh} * VSG_{CS})$

VLCR = $\sum(VLG_{MWh} * VLG_{CS})$

Where:

VSG_{MWh} = the total quantity of MWhs of Virtual Supply that a Customer Bids for all Virtual Supply positions in the Virtual Supply group

VSG_{CS} = the amount of credit support required in $/MWh for the Virtual Supply group

VLG_{MWh} = the total quantity of MWhs of Virtual Load that a Customer Bids for all Virtual Load positions in the Virtual Load group

VLG_{CS} = the amount of credit support required in $/MWh for the Virtual Load group

The ISO will categorize each Virtual Supply Bid into one of the 33 Virtual Supply groups ("VSG") set forth in the Virtual Supply chart below, as appropriate, based upon the season, weekday/weekend, holiday, and time-of-day of the Virtual Supply Bid. For each Load Zone, the amount of credit support required in $/MWh for a Virtual Transaction in a particular Virtual Supply group shall equal the price differential between the Energy price in the Day-Ahead Market and the Energy price in the Real-Time Market, at the 98th percentile, based upon all possible Virtual Supply positions in the Virtual Supply group in the previous one (1) year ending on the last day of the calendar month preceding the month to which the Virtual Supply Bid applies and in the previous five (5) years ending on the last day of the calendar month preceding the month to which the Virtual Supply Bid applies ("Virtual Supply Price Differential"). The

Virtual Supply Price Differential will be calculated by applying a weight of 1/3 to the previous one (1) year ending on the last day of the end of the calendar month preceding the month to which the Virtual Supply Bid applies and a weight of 2/3 to the previous five (5) years ending on the last day of the calendar month preceding the month to which the Virtual Supply Bid applies.

The ISO will categorize each Virtual Load Bid into one of the 28 Virtual Load groups ("VLG") set forth in the Virtual Load chart below, as appropriate, based upon the season, weekday/weekend, holiday, and time-of-day of the Virtual Load Bid. For each Load Zone, the amount of credit support required in $/MWh for a Virtual Transaction in a particular Virtual Load group shall equal the price differential between the Energy price in the Day-Ahead Market and the Energy price in the Real-Time Market, at the 97th percentile, based upon all possible Virtual Load positions in the Virtual Load group in the previous one (1) year ending on the last day of the calendar month preceding the month to which the Virtual Load Bid applies and in the previous five (5) years ending on the last day of the calendar month preceding the month to which the Virtual Load Bid applies ("Virtual Load Price Differential"). The Virtual Load Price Differential will be calculated by applying a weight of 1/3 to the previous one (1) year ending on the last day of the calendar month preceding the month to which the Virtual Load Bid applies and a weight of 2/3 to the previous five (5) years ending on the last day of the calendar month preceding the month to which the Virtual Load Bid applies.

If a Customer submits Bids for both Virtual Load and Virtual Supply for the same day, hour, and Load Zone, then for those Bids, until such time as those Bids have been evaluated by SCUC, only the greater of the Customer's (i) VLCR for the total MWhs Bid for Virtual Load, or (ii) VSCR for the total MWhs Bid for Virtual Supply will be included when calculating the

Customer's Virtual Transaction Component. After evaluation of those Bids by SCUC, then only the credit requirement for the net position of the accepted Bids (in MWhs of Virtual Load or Virtual Supply) will be included when calculating the Customer's Virtual Transaction Component.

Virtual Supply Groups

Summer	**Virtual Supply Group For Each Load Zone**
HB07–09	VSG-1
HB10–12	VSG-2
HB13–17	VSG-3
HB18	VSG-4
HB19-20	VSG-5
HB21-22	VSG-6
Weekend/ Holiday (HB07–08)	VSG-7
Weekend/ Holiday (HB09–12)	VSG-8
Weekend/ Holiday (HB13–14)	VSG-9
Weekend/ Holiday (HB15–16)	VSG-10
Weekend/ Holiday (HB17–18)	VSG-11
Weekend/ Holiday (HB19–22)	VSG-12
Night (HB00,23)	VSG-13
Night (HB01-06)	VSG-14
Winter	
HB08–09	VSG-15
HB10–12	VSG-16
HB13–15	VSG-17
HB16-17	VSG-18
HB18-20	VSG-19
HB21-22	VSG-20
Weekend/ Holiday (HB16–20)	VSG-21
Weekend/ Holiday (Other HB08-22)	VSG-22
Night (HB00,01,23)	VSG-23
Night (HB02-05)	VSG-24

Night (HB06-07)	VSG-25
Rest-of-Year	
HB07–10	VSG-26
HB11–14	VSG-27
HB15–19	VSG-28
HB20-22	VSG-29
Weekend/ Holiday (HB17–20)	VSG-30
Weekend/ Holiday (Other HB07-22)	VSG-31
Night (HB00,06,23)	VSG-32
Night (HB01-05)	VSG-33

Where:

Summer	=	May, June, July, and August
Winter	=	December, January, and February
Rest-of-Year	=	March, April, September, October, and November
Weekend	=	Saturday and Sunday
Holiday	=	NERC-defined holidays
HB	=	Hour Beginning x:00

Virtual Load Groups

Summer	Virtual Load Group For Each Load Zone
HB07–09	VLG-1
HB10–11	VLG-2
HB12-13	VLG-3
HB14-17	VLG-4
HB18-20	VLG-5
HB21-22	VLG-6
Weekend/ Holiday (HB13-19)	VLG-7
Weekend/ Holiday (Other HB07-22)	VLG-8
Night (HB00,23)	VLG-9

Night (HB01-06)	VLG-10
Winter	
HB07–09	VLG-11
HB10–12	VLG-12
HB13–15	VLG-13
HB16-17	VLG-14
HB18-20	VLG-15
HB21-22	VLG-16
Weekend/ Holiday (HB16–20)	VLG-17
Weekend/ Holiday (Other HB07-22)	VLG-18
Night (HB02-04)	VLG-19
Night (Other HB23-06)	VLG-20
Rest-of-Year	
HB07–10	VLG-21
HB11–14	VLG-22
HB15–19	VLG-23
HB20-22	VLG-24
Weekend/ Holiday (HB17–20)	VLG-25
Weekend/ Holiday (Other HB07-22)	VLG-26
Night (HB00,06,23)	VLG-27
Night (HB01-05)	VLG-28

Where:

Summer	=	May, June, July, and August
Winter	=	December, January, and February
Rest-of-Year	=	March, April, September, October, and November
Weekend	=	Saturday and Sunday
Holiday	=	NERC-defined holidays
HB	=	Hour Beginning x:00

26.4.2.7 Reserved for Future Use

26.4.2.8 Reserved for Future Use

26.4.2.9 Projected True-Up Exposure Component

The Projected True-Up Exposure Component shall apply to any Customer whose average percentage credit exposure to the NYISO is greater than ten percent of the initial invoice settlements for the four-month true-ups over the most recent period, not to exceed four months, for which the Customer has been invoiced by the NYISO. Customers subject to the Projected True-Up Exposure Component shall be required to provide secured credit to satisfy the requirement. The Projected True-Up Exposure Component shall be determined according to the following formula:

$$PTE = \left[\sum_{N4} (\text{4 month settlement - associated initial settlement})\right] + \left[\sum_{N8} (\text{Final bill close-out settlement - associated 4 month settlement})\right]$$

Where:

PTE	=	The amount of secured credit support required for the Projected True-Up Exposure Component
N4	=	Each month in the most recent four-month period with a 4 month settlement
N8	=	Each month in the most recent eight-month period with a final bill close-out settlement

26.4.2.10 Former RMR Generator Component

The Former RMR Generator Component shall apply to any Customer that is the financially responsible party under the ISO Tariffs for a former RMR Generator or former Interim Service Provider that is subject to a Monthly Repayment Obligation. The Former RMR Generator Component will apply until either (a) the Monthly Repayment Obligation associated

with the former RMR Generator or former Interim Service Provider is paid in full, or (b) the former RMR Generator or former Interim Service Provider is not subject to a Monthly Repayment Obligation. Customers subject to the Former RMR Generator Component shall be required to provide collateral to satisfy the requirement.

The Former RMR Generator Component shall be calculated as follows:

$$\sum_{G \in S} MRO_G \times Term_G$$

S = the set of former RMR Generators and former Interim Service Providers for which Customer is the financially responsible party under the ISO Tariffs

G = a former RMR Generator or former Interim Service Provider in set S

MRO_G = the Monthly Repayment Obligation (as defined in Section 15.8.7 of Rate Schedule 8 to the Services Tariff) for Generator G

$Term_G$ = the lesser of 8 or the number of months remaining in the repayment term that the ISO determines in accordance with Rate Schedule 8 to the Services Tariff for Generator G

26.4.3 Calculation of Bidding Requirement

The Bidding Requirement shall be an amount equal to the sum of:

(i) the amount of bidding authorization that the Customer has requested for use in or during, as appropriate, an upcoming ISO-administered TCC auction, which shall at least cover the sum of all positive bids to purchase TCCs, plus the absolute value of the sum of all negative offers to sell TCCs; *provided, however,* that the amount of credit required for each TCC that the Customer bids to purchase, whether positive, negative, or zero shall not be less than (a) $3,000 per MW for two-year TCCs, (b) $1,500 per MW for one-year TCCs, (c) $2,000 per MW for six-month TCCs, (d) $1,800 per MW for five-month TCCs, (e) $1,500 per MW

for four-month TCCs, (f) $1,200 per MW for three-month TCCs, (g) $900 per MW for two-month TCCs, and (h) $600 per MW for one-month TCCs;

(ii) the remaining amount that the Customer owes following an upcoming Centralized TCC Auction as a result of purchasing a Fixed Price TCC;

(iii) the amount of bidding authorization that the Customer has requested for use in an upcoming ISO-administered ICAP auction; and

(iv) five (5) days prior to any ICAP Spot Market Auction, the amount that the Customer may be required to pay for UCAP in the auction, calculated as follows:

$$\sum_{L \in S}\left[(ICPM_L * 1000 * Deficiency_L) + (ICPM_L * 1000 * (ZDOMW_L * -1)) + \left(ICPM_L * 1000 * \left(\frac{ZCP_L - 1}{2}\right) * RQT_L\right)\right]$$

Where:

S equals a set containing the following locations: each Locality and Rest of State,

L equals a location in the set *S,*

$ICPM_L$ equals the lesser of $UBRP_L$ or LM_L,

$UBRP_L$ equals the UCAP based reference point (in $/kW-Month) for location *L*, as determined on the ICAP Demand Curve for that location (or for NYCA, if *L* is Rest of State) for the applicable Obligation Procurement Period,

LM_L equals (1) for any Locality *L* that is contained within another Locality *X*, the greater of CPM_L or CPM_X, or (2) for any other Locality or Rest of State, CPM_L,

CPM_L equals for location *L*, $(1 + Margin_L)*MCP_L$,

CPM_X equals for location *X*, $(1 + Margin_X)*MCP_X$,

$Margin_L$ equals 25% if location *L* is New York City and 100% if location *L* is G-J Locality, Long Island or Rest of State,

MCP_L equals the Market-Clearing Price for location *L* in the most recent Monthly Auction that established such a price for the month covered by the ICAP Spot Market Auction, measured in dollars per kilowatt-month,

$Deficiency_L$ equals the number of megawatts of Unforced Capacity that are to be procured in location L on behalf of that Customer in the ICAP Spot Market Auction in order to cover any deficiency for that Customer that exists in that location after the certification deadline for that ICAP Spot Market Auction less any deficiency calculated for that Customer for any Localities contained within location L, such value not to be less than zero,

$ZDOMW_L$ equals the number of megawatts of unsold Unforced Capacity in location L that the Customer committed as zero dollar offered megawatts for that ICAP Spot Market Auction,

ZCP_L equals the percentage determined in accordance with Services Tariff Section 5.14.1.2 for the applicable ICAP Demand Curves as established at the $0.00 point for the appropriate Capability Year, and

RQT_L equals (1) if L is New York City or Long Island, that Customer's share of the Locational Minimum Unforced Capacity Requirement for location L or (2) if L is G-J Locality, that Customer's share of the Locational Minimum Unforced Capacity Requirement for the G-J Locality that remains after reducing this amount by its share of the Locational Minimum Unforced Capacity Requirements for New York City or, (3) if L is Rest of State, that Customer's share of the NYCA Minimum Unforced Capacity Requirement that remains after reducing this amount by (a) its share of the Locational Minimum Unforced Capacity Requirements for New York City and Long Island and (b) that Customer's share of the Locational Minimum Unforced Capacity Requirement for the G-J Locality remaining after accounting for New York City, as calculated in (2) above; such value not to be less than zero.

26.5 Unsecured Credit

A Customer may use Unsecured Credit to satisfy any part of its Operating Requirement or Bidding Requirement other than (i) any credit requirement for bidding on or holding TCCs, (ii) the Projected True-Up Exposure Component, (iii) the Former RMR Generator Component, or (iv) a withdrawing Customer's required collateral. Affiliate guarantees are considered a form of Unsecured Credit.

Upon written request of a Customer, the ISO shall determine the amount of Unsecured Credit to be granted to the Customer, if any, in accordance with the ISO's creditworthiness requirements. Upon a Customer's written request, the ISO will provide a written explanation for any changes in the amount of the Customer's Unsecured Credit.

26.5.1 Eligibility

A Customer may be eligible to receive Unsecured Credit if the Customer meets the following criteria:

(i) Creditworthiness

(a) is an Investment Grade Customer,

(b) is an Unrated Customer that is deemed an Investment Grade Customer pursuant to an Equivalency Rating, or

(c) provides an Affiliate guarantee in compliance with Section 26.5.4 of this Attachment K;

AND

(ii) Payment History

(a) has actively participated in the ISO-Administered markets and paid when due all of its invoices during the immediately preceding six months, or

(b) has actively participated in the markets of another independent system operator or regional transmission organization and has paid when due all of its invoices during the immediately preceding six months. Any Customer relying on its payment history in another market to fulfill the requirement of this Section 26.5.1(ii) must provide evidence satisfactory to the ISO of such payment history.

Notwithstanding the foregoing, a Customer otherwise eligible for Unsecured Credit that fails to respond to the ISO's request to update the Customer's list of Affiliates, within the time frame provided by Section 9.2 of the ISO Services Tariff, shall not be eligible for Unsecured Credit.

26.5.2 Market Concentration Cap

A Customer's Unsecured Credit shall not exceed fifty million dollars ($50M) (the "Market Concentration Cap"). Moreover, the maximum amount of Unsecured Credit extended to a group of Customers that are Affiliates shall not exceed, in the aggregate, the Market Concentration Cap.

26.5.3 Determination of Unsecured Credit

26.5.3.1 Starting Point

The starting point for determining the amount of Unsecured Credit to be granted to an Investment Grade Customer, except as provided otherwise in Section 26.5.3.6 of this Attachment K, shall be a percentage of its Tangible Net Worth, as indicated on the matrix contained in Table K-1, subject to the Market Concentration Cap.

Table K-1 Tangible Net Worth Credit Matrix

Customer Rating	Starting Point for Determining Unsecured

				Credit
Senior Long-term Unsecured Debt Rating		Issuer Rating or Equivalency Rating		(% of Tangible Net Worth)
S&P, Fitch, and Dominion	Moody's	S&P, Fitch, Dominion, and NYISO	Moody's	
A+ or higher	A1 or higher	AA- or higher	Aa3 or higher	7.5%
A	A2	A+	A1	6.5%
A-	A3	A	A2	5.0%
BBB+	Baa1	A-	A3	4.0%
BBB	Baa2	BBB+	Baa1	2.5%
BBB-	Baa3	BBB	Baa2	1.5%
BB+ or lower	Ba1 or lower	BBB- or lower	Baa3 or lower	0%

26.5.3.2 Adjustment to Starting Point

The ISO shall conduct a Credit Assessment of the Customer and shall determine the amount of Unsecured Credit that it shall grant to the Customer by adjusting the Customer's starting point in accordance with the following table:

Starting Point Adjustment

Score Bucket	Public Score Range	Private Score Range	Starting Point Adjustment
1	0.00 – 0.33	0.00 – 0.31	0%
2	0.34 – 0.40	0.32 – 0.39	-20%
3	0.41 – 0.45	0.40 – 0.43	-50%

4	0.46 – 0.50	0.44 – 0.48	-80%
5	0.51+	0.49+	-100%

26.5.3.3 Adjustment to Unsecured Credit

(a) In the event of a change in a Customer's (1) Tangible Net Worth, and/or (2) agency rating, the ISO shall recalculate the Customer's starting point and Unsecured Credit amount in accordance with Sections 26.5.3.1 and 26.5.3.2 of this Attachment K.

(b) The ISO may conduct a Credit Assessment of a Customer at any time and adjust the amount of Unsecured Credit granted to the Customer in accordance with the following table:

Unsecured Credit Adjustment
Current Credit Assessment Score Bucket

Prior Credit Assessment Score Bucket	**Score Bucket**	**1**	**2**	**3**	**4**	**5**
	1	0%	-20%	-50%	-80%	-100%
	2	25%	0%	-38%	-75%	-100%
	3	100%	60%	0%	-60%	-100%
	4	400%	300%	150%	0%	-100%
	5	N/A	N/A	N/A	N/A	N/A

26.5.3.4 Restoration of Unsecured Credit

A Customer that is subject to a 100% reduction of Unsecured Credit shall not be eligible for Unsecured Credit again until the Customer demonstrates two consecutive quarters of financial performance that would otherwise have qualified the Customer for Unsecured Credit in accordance with Sections 26.5.3.1 and 26.5.3.2 of this Attachment K.

26.5.3.5 Credit Assessment

(a) In performing a Credit Assessment, the ISO shall evaluate specified indicators of credit risk pertaining to a Customer, which indicators will vary depending on whether the Customer is categorized by the ISO as a private entity or a public entity. The ISO shall categorize a Customer as private or public, for Credit Assessment purposes, in accordance with the following criteria:

Primary Criteria	Secondary Criteria	Credit Assessment Category
Standalone public trading company	None	Public
Subsidiary of a public company with its parent company as guarantor	None	Public
Subsidiary of a public company	With assets greater than US$10B	Public
Subsidiary of a public company	Contributes 50% or more of its parent company's revenues or accounts for 50% or more of its assets	Public
Subsidiary of a public company	Contributes less than 50% of its parent company's revenues or represents less than 50% of its assets	Private
Does not satisfy the criteria listed above	None	Private

(b) The ISO shall determine the Credit Assessment score for a Customer based upon the market and financial indicators and weightings, as appropriate, set forth below.

Public Entity Indicators **Weight**

- Market Indicators

- Absolute CDS Spread 21.3%
- Relative Stock Decline from 3 month high 4.3%
- Stock Return Volatility (3 month std. deviation) 12.7%

- Size
  - Total Assets 12.7%
- Performance
  - Retained Earnings/Assets 8.5%
- Debt Coverage
  - Total Debt/EBITDA 12.7%
- Leverage
  - Debt/(Total Debt + Equity) 8.5%
- Liquidity
  - Cash/Assets 4.3%
- Qualitative Assessment 15.0%

Private Entity Indicators **Weight**

- Performance
  - Return on Assets 17.5%
  - Profit Margin 10.5%
- Debt Coverage
  - Total Debt/EBITDA 17.5%
- Leverage
  - Total Debt/Total Assets 17.5%
- Liquidity

- Cash/Assets 7.0%

- Qualitative Assessment 30.0%

(c) If one or more of the indicators listed above does not exist for a Customer, then the ISO shall, in its sole discretion, reallocate the weight attributed to that indicator either (1) to the remaining indicators proportionately, or (2) entirely to the qualitative assessment indicator.

(d) The qualitative areas evaluated shall include, but shall not be limited to, the following (as applicable): (1) Affiliate financial and market indicators, (2) ratemaking ability and legal right to fully recover end-user costs, (3) industry characteristics, (4) risk policies and procedures, (5) management quality, (6) ability to access funding in difficult market conditions, and (7) historical relationship and payment history with the ISO. A Transmission Owner that can recover end-user costs pursuant to authority granted by the PSC will receive a qualitative assessment score of no worse than five.

26.5.3.6 Public Power Entities

The following additional provisions shall apply to the determination of a Public Power Entity's Unsecured Credit:

(a) A Public Power Entity that is an Investment Grade Customer shall qualify for one million dollars ($1M) in Unsecured Credit, without regard for its Tangible Net Worth or Credit Assessment. Municipal electric systems that operate through a joint action agency or a similar municipal affiliation agreement acceptable to the ISO may aggregate their Unsecured Credit amounts of one million dollars ($1M)

per member such that the joint action agency will have an Unsecured Credit amount, subject to the Market Concentration Cap, equal to the total of the Unsecured Credit amounts of each individual member. Each such agency will qualify for such aggregated Unsecured Credit treatment subject to the ISO's review of the particular affiliation agreement and the ISO's review of documentation submitted by the agency to demonstrate that it has been formed under the pertinent sections of the New York State Municipal Law.

(b) In lieu of a one million dollar ($1M) grant of Unsecured Credit, a Public Power Entity may request Unsecured Credit based on its Tangible Net Worth and Credit Assessment. In such case, the ISO will consider the Public Power Entity a private entity for Credit Assessment purposes.

26.5.3.7 Government Entities

The following additional provisions shall apply to the determination of a Government Entity's Unsecured Credit:

(a) For purposes of this section, "Government Entity" means (1) a state government and any administrative unit thereof or (2) the government of a locality, including special-purpose districts or authorities, and any administrative unit thereof.

(b) A Government Entity that is an Investment Grade Customer shall qualify for one million dollars ($1M) in Unsecured Credit, without regard for its Tangible Net Worth or Credit Assessment. Affiliations of Government Entities that operate through a joint action agency or a similar municipal affiliation agreement acceptable to the ISO may aggregate their Unsecured Credit amounts of one million dollars ($1M) per member such that the joint action agency will have an

Unsecured Credit amount, subject to the Market Concentration Cap, equal to the total of the Unsecured Credit amounts of each individual member. Each such agency will qualify for such aggregated Unsecured Credit treatment subject to the ISO's review of the particular affiliation agreement and the ISO's review of documentation submitted by the agency to demonstrate that it has been formed under the pertinent sections of the New York State Municipal Law.

(c) In lieu of a one million dollar ($1M) grant of Unsecured Credit, a Government Entity may request Unsecured Credit based on its Tangible Net Worth and Credit Assessment. In such case, the ISO will consider the Government Entity a private entity for Credit Assessment purposes.

26.5.4 Affiliate Guarantees

26.5.4.1 Eligibility

An Affiliate guarantor shall be subject to the ISO's financial assurance requirements as if the Affiliate guarantor were a Customer and shall be assigned a level of Unsecured Credit, if any.

26.5.4.2 Use for Satisfaction of Minimum Capitalization Requirements

A Customer may use an Affiliate guarantor's financial statements to satisfy the capitalization requirement set forth in Section 26.1.1(e) of this Attachment K if (i) no other Customer relies on the Affiliate guarantor's financial statements to satisfy the capitalization requirement, and (ii) the Customer provides an unlimited Affiliate guarantee that satisfies the requirements set forth in Section 26.5.4.3 of this Attachment K. If a Customer provides an Affiliate guarantee solely to satisfy its capitalization requirement, the Affiliate guarantor,

notwithstanding Section 26.5.4.1 of this Attachment K, shall not be subject to the ISO financial assurance requirements.

26.5.4.3 Form of Affiliate Guarantee

An Affiliate guarantee must be in a form acceptable to the ISO and issued by an Investment Grade U.S. or Canadian Affiliate. A Customer's failure to provide a source of collateral in an amount sufficient to (i) secure its obligations to the ISO and/or (ii) as applicable, secure its capitalization requirement pursuant to Section 26.1.1(e) of this Attachment K, fifty (50) days prior to the termination of an Affiliate guarantee, which source of collateral shall be guaranteed to remain in effect for a period of not less than one (1) year, shall be a condition of default enabling the ISO to immediately demand payment under the Affiliate guarantee in the amount required to meet Customer's ISO credit requirements, and/or, as applicable, the amount required to secure Customer's capitalization requirement.

26.5.5 Requests for Changes, Appeals

Requests for changes to the amount of a Customer's Unsecured Credit shall be made in writing to the ISO Credit Manager. Appeals of any decision regarding a Customer's Unsecured Credit shall be made in writing to the ISO's Chief Financial Officer and shall include all necessary supporting documentation. The Chief Financial Officer shall determine all appeals within ten (10) business days.

26.6 Collateral Requirements

As security for the prompt payment of a Customer's obligations to the ISO arising under the Services Tariff or the OATT, including without limitation an obligation to (i) satisfy any credit requirement for bidding on or holding TCCs, and (ii) to the extent that its Operating Requirement and/or Bidding Requirement exceed(s) the total of its Unsecured Credit plus any posted collateral, Customer shall provide to the ISO collateral in an acceptable form in accordance with Section 26.6.1 hereof.

26.6.1 Acceptable Collateral

26.6.1.1 Cash deposit

Customers formed or incorporated in, who are residents of, and whose operations are located primarily within the United States or Canada, may provide a cash deposit as collateral. If a Customer provides cash to the ISO as security for the obligations described above in Section 26.6, the Customer's delivery of cash to the ISO shall constitute the grant of a first-priority security interest in the cash in favor of the ISO and the ISO shall be authorized by such delivery to hold the cash as security and to apply it to the Customer's obligations. The ISO shall be the "customer" with respect to any account into which cash provided hereunder may be held. A Customer who delivers cash to the ISO hereunder agrees that the Tariff and any other agreements incorporating the terms of the Tariff shall for all purposes constitute a security agreement. Customers shall receive actual interest earned on cash deposits.

26.6.1.2 Letter of credit

A letter of credit shall be in a form acceptable to the ISO and issued or guaranteed by an approved U.S. or Canadian commercial bank, or an approved U.S. or Canadian branch of a

foreign bank, with a minimum "A" rating from Standard & Poor's, Fitch, Moody's, or Dominion. A Customer's failure to provide acceptable collateral in an amount sufficient to secure its obligations to the ISO fifty (50) days prior to the termination of a letter of credit, which collateral shall be guaranteed to remain in effect for a period of not less than one (1) year, shall be a condition of default enabling the ISO to immediately draw upon the full value of the letter of credit.

26.6.1.3 Surety Bonds

A surety bond shall be in a form acceptable to the ISO, payable immediately upon demand without prior demonstration of the validity of the demand, and issued by a U.S. Treasury-listed surety with a minimum "A" rating from A.M. Best. A Customer's failure to provide acceptable collateral in an amount sufficient to secure its obligations to the ISO fifty (50) days prior to the termination of a surety bond, which collateral shall be guaranteed to remain in effect for a period of not less than one (1) year, shall be a condition of default enabling the ISO to immediately demand payment of the full value of the surety bond.

26.6.1.4 Netting of Amounts Receivable

A Customer may elect to treat as cash collateral the amount that the ISO determines will be owed to the Customer as of the day after the next regular weekly payment to the Customer and that will be payable to the Customer in the following regular weekly payment; *provided*, *however*, that (i) any such payment to the Customer may be adjusted by the ISO as necessary to correct for any error in this determination, and (ii) the Customer first enter into a security agreement with the ISO in a form acceptable to the ISO. At a minimum, the security agreement must grant to the ISO a continuing, first priority security interest in the Customer's ISO receivables and authorize the ISO to file financing statements, as necessary, at Customer's

expense, to protect the ISO's interest.

26.6.2 Reserved for future use

26.6.3 Alternative Security Arrangements

Alternative security arrangements substantially similar to the credit requirements set forth in this Attachment K may be made in exigent circumstances to protect the financial position of the ISO if proposed by the Customer and approved by the ISO.

26.7 Additional Financial Assurance Policies for External Transactions

26.7.1 ISO Monitoring

The ISO shall monitor the External Transaction Bids submitted by a Customer. If the credit support required for any batch of External Transaction Bids submitted by a Customer exceeds the amount of the Customer's available credit support for External Transactions, then all of the Customer's External Transaction Bids in that batch of Bids shall be rejected by the ISO.

26.7.2 Suspension

If, at any time, the net amount owed to the ISO by a Customer as a result of External Transactions reaches fifty percent (50%) of the credit support provided by the Customer to support its External Transactions, then the ISO shall attempt to contact the Customer to request either payment or additional credit support in the amount then owed by the Customer as a result of its External Transactions.

If the day of the ISO's request stated above falls on a business day and the Customer fails to make payment or provide additional collateral as described above by 4:00 p.m. Eastern Time on the same day as the ISO's request, then the ISO may immediately suspend the Customer's authorization to engage in External Transactions until payment or provision of its required amount of credit support using Unsecured Credit and/or collateral.

If the day of the ISO's request stated above does not fall on a business day, then the ISO may issue a demand for credit support and immediately suspend the Customer's authorization to engage in External Transactions until the Customer makes payment or provides its required amount of credit support using Unsecured Credit and/or collateral.

If, at any time, the amount owed to the ISO by a Customer as a result of its External Transactions reaches one hundred percent (100%) of the credit support provided by the

Customer to support its External Transactions, then the ISO may cancel any pending Day-Ahead Bids before they are accepted and may immediately suspend the Customer's authorization to engage in External Transactions until the Customer makes payment or provides its required amount of credit support using Unsecured Credit and/or collateral.

26.8 Additional Financial Assurance Policies for TCCs

26.8.1 Suspension

If, at any time, the net amount owed by a Customer to the ISO for Congestion Rents reaches fifty percent (50%) of the collateral posted by the Customer to satisfy the TCC Component of its Operating Requirement then the ISO shall attempt to contact the Customer to request either payment or additional collateral in the net amount of the Congestion Rents then owed by the Customer.

If the Customer fails to make payment or provide additional collateral as described above by 4:00 p.m. Eastern Time on the same day as the ISO's request, then the ISO may cancel any pending Bids on TCCs and may immediately suspend the Customer's authorization to Bid on TCCs until the Customer makes payment or provides the required amount of collateral.

26.9 Additional Financial Assurance Policies for Virtual Transactions

26.9.1 ISO Monitoring

The ISO shall monitor the Virtual Transaction Bids submitted by a Customer. If the credit support required for any batch of Virtual Transaction Bids submitted by a Customer exceeds the amount of the Customer's available credit support for Virtual Transactions, then all of the Customer's Virtual Transaction Bids in that batch of Bids shall be rejected by the ISO.

26.9.2 Suspension

If, at any time, the net amount owed to the ISO by a Customer as a result of Virtual Transactions reaches fifty percent (50%) of the credit support provided by the Customer to support its Virtual Transactions, then the ISO shall attempt to contact the Customer to request either payment or additional credit support in the amount then owed by the Customer as a result of its Virtual Transactions.

If the day after the ISO's request stated above falls on a business day and the Customer fails to make payment or provide additional credit support as described above by 4:00 p.m. on that next business day, then the ISO may immediately suspend the Customer's authorization to engage in Virtual Transactions until payment or provision of its required amount of credit support using Unsecured Credit and/or collateral.

If the day after the ISO's request does not fall on a business day, then the ISO may issue a demand for credit support and immediately suspend the Customer's authorization to engage in Virtual Transactions until the Customer makes payment or provides its required amount of credit support using Unsecured Credit and/or collateral.

If, at any time, the amount owed to the ISO by a Customer as a result of its Virtual Transactions reaches one hundred percent (100%) of the credit support provided by the

Customer to support its Virtual Transactions, then the ISO may cancel any pending Day-Ahead Bids before they are accepted and may immediately suspend the Customer's authorization to engage in Virtual Transactions until the Customer makes payment or provides its required amount of credit support using Unsecured Credit and/or collateral.

26.10 Reserved for future use.

26.11 Additional Financial Assurance Policies for Wholesale Transmission Service Charges

26.11.1 Application of Security

In the event a Transmission Owner declares a certain WTSC overdue and satisfies the requirements specified in Section 26.11.2 below, the NYISO will reimburse the Transmission Owner for part, or all, of the unpaid amount.

To the extent a Market Participant's Unsecured Credit does not satisfy the Market Participant's Operating Requirement, the NYISO will collect and hold collateral calculated pursuant to the WTSC Component of the Operating Requirement to secure payments owed by Customers to Transmission Owners. Any security held by the ISO for a Customer in excess of the amount collected pursuant to the WTSC Component of the Operating Requirement shall be available to secure WTSC only to the extent the ISO determines that such collateral will not be necessary to secure any payment obligations to the ISO, including true-up payments and other anticipated invoice adjustments. The ISO shall have access to any collateral collected pursuant to the WTSC Component of the Operating Requirement only to the extent that the ISO determines such collateral is not necessary to secure WTSC payment obligations to Transmission Owners.

26.11.2 Prerequisites to NYISO Action

The following conditions must be fully satisfied before the NYISO takes action to address a WTSC nonpayment:

26.11.2.1 The WTSC payment must be at least ten (10) days overdue, as measured from the due date on the invoice sent to the Customer by the Transmission Owner;

26.11.2.2 The Transmission Owner must have issued a late notice and demand letter to the Customer specifying both the amount and period by which the WTSC payment is overdue;

26.11.2.3 The Transmission Owner must have made an additional, informal attempt to collect the overdue WTSC payment from the Customer which may be, without limitation, a telephone call or meeting with appropriate personnel (the method of such additional informal attempt shall be at the Transmission Owner's discretion); and

26.11.2.4 The Transmission Owner must provide to the ISO, by certified mail or other verifiable delivery method, a copy of the initial invoice sent to the Customer, a copy of the late notice and demand letter with proof of receipt by the Customer, an indemnification of the ISO regarding the liabilities discussed in Section 26.11.3 below, a request that the NYISO draw upon available collateral to satisfy the default, and a sworn statement by an officer of the Transmission Owner stating: (a) that the WTSC payment is due and owing, (b) the period by which the WTSC payment is overdue, (c) a recitation of the Transmission Owner's collection efforts (including the additional, informal attempt to collect the debt).

26.11.3 NYISO Action

On the first business day after the ISO has received the notice that satisfies the requirements listed in Section 26.11.2.4 above, the ISO: (i) shall send a final demand for payment of the WTSC to the Customer within two (2) business days; (ii) shall initiate a draw upon available collateral for the benefit of the affected Transmission Owner if the WTSC due is

not paid within two (2) business days of the letter; and (iii) may begin termination proceedings in accordance with the NYISO tariffs.

26.11.4 Transmission Owner Indemnification to the NYISO

As a prerequisite for ISO action listed in Section 26.11.3 above, the Transmission Owner will indemnify and hold the ISO harmless against liability arising out of the use of security to satisfy a WTSC nonpayment, any proceeding to terminate service, or termination of service to a customer except to the extent the dispute arises out of the ISO's reporting to the Transmission Owner of whether the underlying wheel through, internal wheel or export transaction(s) actually occurred and the details of the transaction.

26.12 Request for Additional Credit Support

If, at any time, the ISO requests additional credit support from a Customer to meet a shortfall, the Customer shall, within two (2) business days from the date of the request, or any shorter time period specified by the ISO or otherwise required by the ISO Tariffs, allocate Unsecured Credit and/or post collateral in an amount sufficient to cover the shortfall.

26.13 Withdrawing Customer's Collateral

Upon a Customer's withdrawal from the LBMP Market(s) and/or all of the ISO-Administered Markets, the ISO shall retain all secured credit held by the ISO on behalf of the Customer as of the date of withdrawal until the Customer's final bill close-out settlement is complete and Customer has fulfilled all payment obligations to the ISO. The ISO will use the retained secured credit to secure the Customer's remaining financial obligations, including, but not limited to, true-up payments or any other invoice adjustments.

26.14 Material Adverse Change

The amount of Unsecured Credit granted to a Customer, if any, and the amount of the Customer's Operating Requirement shall be subject to change, at the discretion of the ISO, in the event that there is a material adverse change affecting the risk of nonpayment by the Customer, which includes, but is not limited to: (a) a material change in financial status pursuant to Section 26.2.1.4 of this Attachment K, (b) Customer's failure to timely cure its default under the ISO Tariffs or the tariffs of another independent system operator or regional transmission organization, (c) the issuance of a notice of alleged violation or show cause order, imposition of a sanction or other administrative order by the Federal Energy Regulatory Commission, the Commodity Futures Trading Commission, Environmental Protection Agency, New York State Public Service Commission, New York State Department of Environmental Conservation or any other regulatory body, independent system operator, or regional transmission organization, including the ISO, which could have a material adverse effect on the Customer's financial condition, (d) a downgrade of an Equivalency Rating, (e) a significant change in the Customer's "Expected Default Frequency (EDF)" as determined by Moody's KMV CreditEdge, (f) a significant variation in the Customer's credit evaluation, (g) a significant increase in a Customer's credit default swap (CDS) spreads, (h) a significant decline in a Customer's market capitalization, or (i) an event or circumstance indicating that the Customer may present an unreasonable credit risk to the ISO Administered Markets, which may be identified based on the material Customer provides to the ISO pursuant to Section 26.1.4 of Attachment K of the ISO Services Tariff. In the event the ISO invokes its rights pursuant to this Section 26.14, the ISO will provide the affected Customer with a written explanation of the reasons the ISO declared a material adverse change.

Appendix K-1 - Form Of Customer Prepayment Agreement

THIS PREPAYMENT AGREEMENT, effective as of **[date]** ("Prepayment Agreement") is entered into by and between the New York Independent System Operator, Inc. ("NYISO") and **[full legal name of customer]** ("Customer"). Capitalized terms used and not otherwise defined herein shall have the meaning ascribed to those terms in the Open Access Transmission Tariff ("OATT") or the Market Administration and Control Area Services Tariff ("Services Tariff"), as context requires.

1. Prepayment to Reduce Operating Requirement. Customer agrees to make a payment each week for purchases of Energy and Ancillary Services ("Prepayment") in order to reduce the Energy and Ancillary Services Component of its Operating Requirement pursuant to Section 26.4.2.1 of Attachment K of the Services Tariff.

2. Prepayment Amount. The amount of each Prepayment ("Prepayment Amount") shall be the NYISO's reasonable estimate, based on the charges incurred by Customer during the previous week, of the charges that Customer will incur during the following week for purchases of Energy and Ancillary Services in the NYISO-administered markets. The initial Prepayment Amount is $**[amount]**. NYISO shall inform Customer of any change in the Prepayment Amount not later than 11:00 A.M. EST on the last business day prior to the day on which the next Prepayment is due. Amounts owed to Customer by NYISO in regular weekly settlements shall not reduce or offset the Prepayment Amount.

3. Manner and Timing of Payment. Customer shall make each Prepayment not later than 4:00 P.M. EST on the second business day after the NYISO requests Prepayment by wire transfer, or other payment method, if any, authorized by ISO Procedures, to the account designated by NYISO.

4. Supplemental Payment. In the event that NYISO determines that a Prepayment is less than the charges incurred or estimated to be incurred by Customer for purchases of Energy and Ancillary Services in the week for which the Prepayment is made, Customer shall make a supplemental payment upon written demand by NYISO. NYISO shall specify in its demand the amount of the supplemental payment and the time for such payment to be made; *provided, however*, that the payment shall not be due sooner than 4:00 P.M. EST on the next business day.

5. Overpayment. In the event that NYISO determines that a Prepayment exceeds the charges incurred or estimated to be incurred by Customer for purchases of Energy and Ancillary Services in the week for which the Prepayment is made, NYISO shall credit the difference toward Customer's next Prepayment and shall notify Customer of the revised Prepayment Amount.

6. Termination. Customer may terminate this Prepayment Agreement upon ten (10) days written notice to NYISO. NYISO may terminate this Prepayment Agreement immediately upon written notice to the Customer in the event that Customer fails to perform in strict accordance with the terms hereof. In addition, this Prepayment Agreement shall terminate upon any amendment of the OATT or the Services

Tariff that eliminates the prepayment mechanism thereunder or requires material modification of this Prepayment Agreement.

7. Regular Weekly Settlements. Nothing in this Prepayment Agreement shall alter the obligation of Customer or NYISO to pay amounts owed in accordance with the NYISO's regular weekly settlement process pursuant to the terms of the OATT and the Services Tariff, which amounts shall be net of payments made pursuant to this Prepayment Agreement.

8. Interest. Customer shall not earn interest on its Prepayments. NYISO shall apply any interest actually earned on Prepayments to offset NYISO costs otherwise recovered through Schedule 1 of the OATT and Rate Schedule 1 of the Services Tariff.

9. Communications. All communications pursuant to this Prepayment Agreement shall be in writing, deemed effective when received, and delivered by hand with receipt of delivery, registered mail, or facsimile with confirmation of receipt to the following addresses:

NYISO:

Attn: Credit Manager

New York Independent System Operator, Inc.

10 Krey Boulevard

Rensselaer, New York 12144

Fax: (518) 356-7505

Customer:

Attn: _____

_____

_____

Fax: _____

NYISO or Customer may change the address provided for receipt of communications pursuant to this Prepayment Agreement by providing written notice to the other party.

10. Expenses. Customer shall pay all reasonable costs incurred by NYISO to enforce this Prepayment Agreement, including attorney fees and expenses.

11. Amendment and Waiver. The terms and provisions of this Prepayment Agreement may not be amended or waived except in writing and signed by NYISO and Customer.

12. Entire Agreement. This Prepayment Agreement embodies the entire agreement between NYISO and Customer with respect to the matters set forth herein, and supersedes all prior such agreements.

13. Severability. Should any provision of this Prepayment Agreement be determined by a court of competent jurisdiction to be unenforceable, all of the other provisions shall remain effective.

14. Choice of Law; Jurisdiction; Venue; and Service of Process. This Prepayment Agreement shall be governed by the laws of the State of New York without regard to conflict of laws principles. Customer irrevocably submits to the jurisdiction of any New York court or any United States court sitting in New York over any action or proceeding arising out of or relating to this Prepayment Agreement and irrevocably agrees that all claims in such action or proceeding may be heard and determined by such court. Customer agrees that a final judgment in any such action or proceeding shall be conclusive and may be enforced in other jurisdictions by suit on the judgment or in any other manner provided by law. Customer waives any objection to venue on the basis of forum non conveniens. Customer irrevocably consents to the service of process in any action or proceeding by the mailing of copies of such process to Customer at its address set forth herein. Customer agrees that any action or proceeding brought against NYISO shall be brought only in a New York court or a United States court sitting in New York. Nothing herein shall affect the right of NYISO to bring any action or proceeding against the Customer or its property in the courts of any other jurisdictions.

15. Waiver of Jury Trial. CUSTOMER IRREVOCABLY, VOLUNTARILY, AND WITH ADVICE OF COUNSEL WAIVES ANY RIGHTS IT MAY HAVE TO A TRIAL BY JURY IN ANY ACTION ARISING IN CONNECTION WITH THIS PREPAYMENT AGREEMENT.

IN WITNESS WHEREOF, NYISO and Customer have caused this Prepayment Agreement to be executed by their respective authorized officials.

New York Independent System Operator, Inc.

By:

Name:

Title:

[Customer]

By:

Name:

Title:

27 Attachment L

Reserved for future use.

28 Reserved for future use

29 Attachment N – External Transactions at The Proxy Generator Buses Associated With The Cross-Sound Scheduled Line, Neptune Scheduled Line, Linden VFT Scheduled Line, and HTP Scheduled Line

29.1 Supremacy of Attachment N

External Transactions at the Proxy Generator Buses associated with the Cross-Sound Scheduled Line, the Neptune Scheduled Line, the Linden VFT Scheduled Line, and the HTP Scheduled Line shall be Bid and scheduled pursuant to the provisions of the ISO Services Tariff and the ISO OATT, and in accordance with this Attachment N. In the event of a conflict between the provisions of this Attachment N and any other provision of the ISO OATT, the ISO Services Tariff, or any of their attachments and schedules, with regard to External Transactions at the Proxy Generator Buses associated with the Cross-Sound Scheduled Line, the Neptune Scheduled Line, the Linden VFT Scheduled Line, or the HTP Scheduled Line, the provisions of this Attachment N shall prevail.

External Transactions at the Proxy Generator Bus associated with the Champlain Hudson Power Express MTF shall be Bid and scheduled pursuant to the provisions of the ISO Services Tariff and OATT, and in accordance with OATT Attachment II (Section 41).

29.2 Transmission Reservations on the Cross-Sound Scheduled Line, the Neptune Scheduled Line, the Linden VFT Scheduled Line, and the HTP Scheduled Line

Customers scheduling External Transactions at the Proxy Generator Buses associated with the Cross-Sound Scheduled Line, the Neptune Scheduled Line, the Linden VFT Scheduled Line, or the HTP Scheduled Line must first hold an Advance Reservation on the appropriate Scheduled Line sufficient to support the proposed External Transaction. Advance Reservations must be obtained in accordance with (a) the Cross-Sound Scheduled Line release procedures that are set forth in Schedule 18 and the Schedule 18 Implementation Rule of the ISO New England Inc. Transmission, Markets and Services Tariff, or any successors thereto, or (b) the Neptune release procedures that are established pursuant to Section 38 of the PJM Interconnection, L.L.C. ("PJM") Open Access Transmission Tariff and set forth in a separate service schedule under the PJM Open Access Transmission Tariff, or (c) the Linden VFT Scheduled Line release procedures that are established pursuant to Section 38 of the PJM Open Access Transmission Tariff and set forth in a separate service schedule under the PJM Open Access Transmission Tariff, or (d) the HTP Scheduled Line release procedures that are established pursuant to Section 38 of the PJM Open Access Transmission Tariff and set forth in a separate service schedule under the PJM Open Access Transmission Tariff.

Customers that have obtained Advance Reservations and wish to schedule 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 must (a) schedule an External Transaction with the ISO by submitting appropriate bids for economic evaluation, and (b) correspondingly schedule a transaction over the Cross-Sound Scheduled Line, the Neptune Scheduled Line, the Linden VFT Scheduled Line, or the HTP Scheduled Line (as appropriate) in accordance with all applicable tariffs and market rules of the Control Area in which the Scheduled Line is located.

If a Customer scheduling External Transactions at the Proxy Generator Buses that are associated with the Cross-Sound Scheduled Line, the Neptune Scheduled Line, the Linden VFT Scheduled Line, or the HTP Scheduled Line inaccurately claims to hold an Advance Reservation or Advance Reservations that are adequate to support its Bid(s), or falsely implies that it has an Advance Reservation or Advance Reservations that are adequate to support its Bid(s) by scheduling such an External Transaction, the ISO may inform the Commission and take other appropriate action.

29.3 Additional Scheduling Rules for the Cross-Sound Scheduled Line, the Neptune Scheduled Line, the Linden VFT Scheduled Line, and the HTP Scheduled Line

29.3.1 Bid Submission and E-Tags for Day-Ahead Transactions

Customers seeking to Schedule Day-Ahead 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 (a) shall comply with all applicable ISO Procedures, and (b) shall submit bids that reference valid NERC E-Tags for their transaction(s) no later than 10 minutes prior to the close of the DAM.

29.3.2 Bids and E-Tags for Real Time Transactions

Customers seeking to schedule Real-Time Market 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 (a) shall comply with all applicable ISO Procedures, and (b) shall submit Bids that reference valid NERC E-Tags for their transaction(s) at least 85 minutes before the start of each dispatch hour.

29.3.3 E-Tags Shall Each Reference One Advance Reservation ID

NERC E-Tags 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 shall each reference no more than one (a) Cross-Sound Scheduled Line Advance Reservation ID or “assignment reference number” from the Cross-Sound Cable, LLC node of the ISO-NE OASIS, or (b) assignment reference number or other designation associated with the grant of scheduling rights over the Neptune Scheduled Line, the Linden VFT Scheduled Line, or the HTP Scheduled Line (as appropriate).

30 Attachment O - Market Monitoring Plan

30.1 INTRODUCTION AND PURPOSE

30.1.1 Purposes and Objectives

This Market Monitoring Plan is intended to provide for the independent, impartial and effective monitoring of and reporting on: (1) the competitive structure, performance and economic efficiency of the New York Electric Markets; (2) the conduct of Market Parties, including but not limited to any exercise or attempt to exercise market power or restrain competition in any New York Electric Market by any Market Party or group of Market Parties; (3) the operation and use of the New York State Transmission System as such system affects or may affect competitive conditions in or the economic efficiency of any of the New York Electric Markets, including but not limited to the nature, extent and causes of any congestion on such system and the costs of or charges for such congestion; (4) the adequacy and effectiveness of any tariff or services agreement, or any rule, standard or procedure, or any market power mitigation or other remedial measures, implemented, administered or overseen by the New York Independent System Operator, Inc. ("ISO") and that affects or could affect the competitiveness or economic efficiency of any of the New York Electric Markets; and (5) any other condition, function or action affecting the foregoing.

Attachment O provides for review and evaluation by the Market Monitoring Unit of the ISO's: (i) Tariffs and market rules, including the ISO's imposition of appropriate measures for the mitigation of market power and imposition of appropriate sanctions or other remedial measures for actions or inaction that the ISO is authorized to address or remedy in its Tariffs; and (ii) administration of the New York Electric Markets. In addition, Attachment O requires the Market Monitoring Unit to timely: (a) report any failure by a Market Party or by the ISO to comply with any tariff or services agreement, or any law, regulation, rule, standard or procedure,

including any market power mitigation or other remedial measure, if such violation or failure to comply impairs or threatens to impair the competitiveness or economic efficiency of any of the New York Electric Markets; (b) submit to the FERC, or other appropriate regulatory or enforcement agency, evidence of possible violation of state or federal law for the preservation of competition (including violations of FERC's regulations and the ISO Tariff rules); and (c) report on perceived market design flaws that the Market Monitoring Unit believes could be effectively remedied by rule or tariff changes. Attachment O is intended to minimize interference with open and competitive markets.

30.1.2 Implementation of Attachment O

All persons or entities responsible for the implementation of Attachment O shall do so in a manner consistent with and intended to achieve both: (i) the creation and operation of New York Electric Markets that are robust, competitive, efficient and non-discriminatory; and (ii) the safe and reliable operation of the electric system in New York Control Area.

30.1.3 Persons and Entities Subject to Attachment O

The ISO, the Market Monitoring Unit, and any person or entity participating in any of the New York Electric Markets or that takes service under or is a party to any tariff or agreement administered by the ISO, shall be subject to the terms, conditions and obligations of Attachment O. Entities that are subject to Attachment O may also be held responsible for actions or inaction by their Affiliates.

30.2 Definitions

For purposes of Attachment O, capitalized terms shall have the meanings specified below, or in the New York Independent System Operator Agreement or Market Administration and Control Area Services Tariff:

Affiliate

For purposes of Attachment O, "Affiliate" includes both Affiliates, as defined in the ISO Services Tariff and, where appropriate, Affiliated Entities, as defined in the Market Mitigation Measures.

Board

"Board" shall mean the Board of Directors of the New York Independent System Operator, a not-for-profit New York corporation.

Core Market Monitoring Functions

"Core Market Monitoring Functions" or "Core Functions" shall mean the duties that the FERC determined the Market Monitoring Unit must be responsible for performing in Order 719. The Core Functions are set forth in Section 30.4.5 of Attachment O.

Interested Government Agencies

"Interested Government Agencies" shall mean the FERC and the New York Public Service Commission.

ISO Market Power Mitigation Measures

"ISO Market Power Mitigation Measures" or "Market Mitigation Measures" shall mean Attachment H to the ISO's Market Administration and Control Area Services Tariff, or any successor provisions thereto.

Market Mitigation and Analysis Department

"Market Mitigation and Analysis Department" or "MMA" shall mean a department, internal to the ISO that is responsible for participating in the ISO's administration of its Tariffs. The MMA's duties are described in Section 30.3, below.

Market Monitoring Unit

"Market Monitoring Unit" shall mean the consulting or other professional services firm, or other similar entity, retained by the Board, as specified in Section 30.4.2 of Attachment O, that is responsible for carrying out the Core Market Monitoring Functions and the other functions that

are assigned to it in Attachment O. The Market Monitoring Unit shall recommend Tariff and market rule changes, but shall not participate in the administration of the ISO's Tariffs, except as specifically authorized in Attachment O.

Market Party

"Market Party" shall mean any person or entity that is a buyer or a seller in, or that makes bids or offers to buy or sell in, or that schedules or seeks to schedule transactions with the ISO in or affecting, any of the New York Electric Markets, or any combination of the foregoing. Under Attachment O and the ISO's Market Mitigation Measures, Market Parties may be held responsible for the actions of, or inaction by, their Affiliates.

Market Violation

"Market Violation" shall mean any of (i) a tariff violation, (ii) violation of a Commission-accepted or approved order, rule or regulation including, but not limited to, violations of FERC's Market Behavior Rules, 18 CFR § 35.41, or any successor provisions thereto, (iii) market manipulation (*see* 18 CFR § 1c.2, or any successor provision thereto), or (iv) inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies.

New York Electric Markets

"New York Electric Markets" shall mean the LBMP Market, the Wholesale Market, any market for the purchase or sale of TCCs, and any other market administered, coordinated or facilitated by, or involving transmission or other services scheduled or otherwise provided by, the ISO.

Order 719

"Order 719" shall mean the Order issued by the FERC on October, 17, 2008 in Docket Nos. RM07-19-000 and AD07-7-000, including the regulations adopted by FERC in that Order, as amended by any subsequent orders issued by the FERC or by a Federal court of appeals.

Other State Commission

"Other State Commission" shall mean the State regulatory agencies other than the New York Public Service Commission that possess primary jurisdiction over (a) the construction and siting of electric transmission and generating facilities, and/or (b) the regulation of retail electric rates, within their respective State.

Plan (Attachment O)

"Plan" shall mean this ISO Market Monitoring Plan (Attachment O).

Protected Information

"Protected Information" shall mean: (a) information that is confidential, proprietary, commercially valuable or competitively sensitive or is a trade secret, (b) information that is Confidential Information under Attachment F to the ISO OATT, (c) information that the Market

Monitoring Unit or the ISO is obligated by tariff, regulation or law to protect, (d) information which, if revealed, would present opportunities for collusion or other anticompetitive conduct, or that could facilitate conduct that is inconsistent with economic efficiency, (e) information relating to ongoing investigations and monitoring activities (including the identity of the person or Market Party that requested or is the subject of an investigation, unless such party consents to disclosure), (f) information subject to the attorney-client privilege, the attorney work product doctrine, or concerning pending or threatened litigation, or (g) information that has been designated as such in writing by the party supplying the information to the ISO or to its Market Monitoring Unit, or by the ISO or its Market Monitoring Unit, provided that such designation is consistent with the ISO's tariffs and this Plan.

30.3 NYISO Market Mitigation And Analysis Department

30.3.1 Establishment

The ISO shall establish, and provide appropriate staffing and resources for, its internal Market Mitigation and Analysis Department ("MMA").

30.3.2 Staffing

The MMA shall be comprised of full-time employees of the ISO having the experience and qualifications necessary to assist the ISO's efforts to implement its obligations under its Tariffs and under Attachment O, including providing support to the ISO's external Market Monitoring Unit where and when needed. In carrying out its responsibilities, the MMA, may retain such consultants and other experts as the ISO deems appropriate to the effective implementation of Attachment O, subject to the management oversight of the Chief Executive Officer ("CEO") or the CEO's designee, the Chief Operating Officer ("COO"). Such consultants or other experts shall comply with applicable ISO policies on conflicts of interest or other standards of conduct.

30.3.3 Duties of MMA

The MMA shall not be responsible for carrying out any of the Core Functions. Rather, the MMA is responsible for working collaboratively with the Market Monitoring Unit and other ISO departments to assist the ISO's efforts to carry out its Tariff responsibilities, including the ISO's obligation to provide adequate data and support to its Market Monitoring Unit. The MMA's duties shall include: (1) administering mitigation in accordance with the ISO's Tariffs, which will include performing daily monitoring of the ISO's markets to identify potential violations of the Market Mitigation Measures, (2) assisting the ISO's efforts to accurately and effectively implement the requirements of its Tariffs and its intended market design,

(3) responding to information and data requests the ISO receives from the FERC's Office of Enforcement staff and from the staff of the New York Department of Public Service, consistent with the provisions of Attachment O, the ISO's Code of Conduct, and any other provisions of the ISO's Tariffs that address the protection of Protected Information, (4) providing data and other assistance to support the Market Monitoring Unit, (5) working collaboratively with other ISO departments to analyze market outcomes, and (6) bringing to the Market Monitoring Unit's attention market-related concerns (including, but not limited to, possible Market Violations) it identifies while carrying out its responsibilities; and (7) participate in and review the ISO's development, implementation and administration of RMR Agreements and associated tariff provisions.

30.3.4 Accountability

The MMA shall act at the direction of the CEO or the CEO's designee, the COO, who shall be accountable for the ISO's implementation of Attachment O.

The CEO or the CEO's designee, the COO, shall ensure that the MMA has adequate employees, funding and other resources, access to required information, and the cooperation of other ISO staff, as necessary for it to perform its duties under Attachment O and under the ISO's Market Mitigation Measures.

30.4 Market Monitoring Unit

30.4.1 Mission of the Market Monitoring Unit

The Market Monitoring Unit's goals are (1) to ensure that the markets administered by the ISO function efficiently and appropriately, and (2) to protect both consumers and participants in the markets administered by the ISO by identifying and reporting Market Violations, market design flaws and market power abuses to the Commission in accordance with Sections 30.4.5.3 and 30.4.5.4 below.

30.4.2 Retention and Oversight of the Market Monitoring Unit

The Board shall retain a consulting or other professional services firm, or other similar entity, to advise it on the matters encompassed by Attachment O and to carry out the responsibilities that are assigned to the Market Monitoring Unit in Attachment O. The Market Monitoring Unit selected by the Board shall have experience and expertise appropriate to the analysis of competitive conditions in markets for electric capacity, energy and ancillary services, and financial instruments such as TCCs, and to such other responsibilities as are assigned to the Market Monitoring Unit under Attachment O, and must also have sufficient resources and personnel to be able to perform the Core Functions and other assigned functions.

The Market Monitoring Unit shall be accountable to the non-management members of the Board, and shall serve at the pleasure of the non-management members of the Board.

30.4.3 Market Monitoring Unit Ethics Standards

The Market Monitoring Unit, including all persons employed thereby, shall comply at all times with the ethics standards set forth below. The Market Monitoring Unit ethics standards set forth below shall apply in place of the standards set forth in the ISO's OATT Attachment F Code

of Conduct, and/or the more general policies and standards that apply to consultants retained by the ISO.

30.4.3.1 The Market Monitoring Unit and its employees must have no material affiliation with any Market Party or Affiliate of any Market Party.

30.4.3.2 The Market Monitoring Unit and its employees must not serve as an officer, employee, or partner of a Market Party.

30.4.3.3 The Market Monitoring Unit and its employees must have no material financial interest in any Market Party or Affiliate of a Market Party. Ownership of mutual funds by Market Monitoring Units and their employees that contain investments in Market Parties or their Affiliates is permitted so long as: (a) the fund is publicly traded; (b) the fund's prospectus does not indicate the objective or practice of concentrating its investment in Market Parties or their Affiliates; and (c) the Market Monitoring Unit/Market Monitoring Unit employee does not exercise or have the ability to exercise control over the financial interests held by the fund.

30.4.3.4 The Market Monitoring Unit and its employees are prohibited from engaging in transactions in the markets administered by the ISO, other than in the performance of duties under the ISO's Tariffs. This provision shall not, however, prevent the Market Monitoring Unit, or its employees, from purchasing electricity, power and Energy as retail customers for their own account and consumption.

30.4.3.5 The Market Monitoring Unit and its employees must not be compensated, other than by the ISO, for any expert witness testimony or other commercial

services, in connection with any legal or regulatory proceeding or commercial transaction relating to the ISO or to the markets that the ISO administers.

30.4.3.6 The Market Monitoring Unit and its employees may not accept anything that is of more than *de minimis* value from a Market Party.

30.4.3.7 The Market Monitoring Unit and its employees must advise the Board in the event they seek employment with a Market Party, and must disqualify themselves from participating in any matter that could have an effect on the financial interests of that Market Party until the outcome of the matter is determined.

30.4.3.8 If the Market Monitoring Unit or any of its employees provide services to entities other than the ISO, the Market Monitoring Unit shall provide to the ISO's Board, and shall regularly update, a list of such entities and services. When the Market Monitoring Unit issues an opinion, report or recommendation to, for or addressing the ISO or the markets it administers that relates to, or could reasonably be expected to affect, an entity (other than the ISO) to which the Market Monitoring Unit or its employees provide services, the Market Monitoring Unit shall inform the ISO's Board of the opinion, report or recommendation it has issued, and that its opinion, report or recommendation relates to, or could reasonably be expected to affect, an entity to which the Market Monitoring Unit or its employees provide services.

30.4.4 Duties of the Market Monitoring Unit

The Market Monitoring Unit shall advise the Board, shall perform the Core Functions specified in Section 30.4.5 of Attachment O, and shall have such other duties and responsibilities

as are specified in Attachment O. The Market Monitoring Unit may, at any time, bring any matter to the attention of the Board that the Market Monitoring Unit may deem necessary or appropriate for achieving the purposes, objectives and effective implementation of Attachment O.

The Market Monitoring Unit shall not participate in the administration of the ISO's Tariffs, except for performing its duties under Attachment O. The Market Monitoring Unit shall not be responsible for performing purely administrative duties, such as enforcement of late fees or Market Party reporting obligations, that are not specified in Attachment O. The Market Monitoring Unit may (i) provide, or assist the ISO's efforts to develop, the inputs required to conduct mitigation, and (ii) assist the ISO's efforts to conduct "retrospective" mitigation (*see* Order 719 at PP. 369, 375) that does not change bids or offers (including physical bid or offer parameters) at or before the time such bids or offers (including physical bid or offer parameters) are considered in the ISO's market solution.

30.4.5 Core Market Monitoring Functions

The Market Monitoring Unit shall be responsible for performing the following Core Functions:

30.4.5.1 Evaluate existing and proposed market rules, tariff provisions and market design elements and recommend proposed rule and tariff changes to the ISO, to the Commission's Office of Energy Market Regulation staff, and to other interested entities, including the New York Public Service Commission, and participants in the ISO's stakeholder governance process. Provided that:

30.4.5.1.1 The Market Monitoring Unit is not responsible for systematic review of every tariff and market rule; its role is monitoring, not audit.

30.4.5.1.2 The Market Monitoring Unit is not to effectuate its proposed market design itself.

30.4.5.1.3 The Market Monitoring Unit's role in recommending proposed rule and Tariff changes is advisory in nature, unless a Tariff provision specifically concerns actions to be undertaken by the Market Monitoring Unit itself.

30.4.5.1.4 The Market Monitoring Unit must limit distribution of issues or concerns it identifies, and its recommendations to the ISO and to Commission staff in the event it believes broader dissemination could lead to exploitation. Limited distributions should include an explanation of why further dissemination should be avoided at that time.

30.4.5.2 Review and report on the performance of the wholesale markets to the ISO, the Commission, and other interested entities such as the New York Public Service Commission and participants in its stakeholder governance process on at least a quarterly basis, and issue a more comprehensive annual state of the market report. The Market Monitoring Unit may issue additional reports as necessary.

30.4.5.2.1 In order to perform the Core Functions, the Market Monitoring Unit shall perform daily monitoring of the markets that the ISO administers. The Market Monitoring Unit's daily monitoring shall include monitoring of virtual bidding.

30.4.5.2.2 The Market Monitoring Unit shall submit drafts of each of its reports to the ISO for review and comment sufficiently in advance of the report's issuance to provide an effective opportunity for review and comment by the ISO. The Market Monitoring Unit may disregard any suggestions with which it disagrees. The ISO may not alter the reports prepared by the Market Monitoring Unit, nor

dictate the Market Monitoring Unit's conclusions.

30.4.5.3 Identify and notify the Commission staff of instances in which a Market Party's or the ISO's behavior may require investigation, including, but not limited to, suspected Market Violations.

30.4.5.3.1 Except as provided in Section 30.4.5.3.2 below, in compliance with § 35.28(g)(3)(iv) of the Commission's regulations (or any successor provisions thereto) the Market Monitoring Unit shall submit a non-public referral to the Commission in all instances where it has obtained sufficient credible information to believe a Market Violation has occurred. Once the Market Monitoring Unit has obtained sufficient credible information to warrant referral to the Commission, the Market Monitoring Unit shall immediately refer the matter to the Commission and desist from further investigation of independent action related to the alleged Market Violation, except at the express direction of the Commission or Commission staff. The Market Monitoring Unit may continue to monitor for repeated instances of the reported activity by the same or other entities and shall respond to requests from the Commission for additional information in connection with the alleged Market Violation it has referred.

30.4.5.3.2 The Market Monitoring Unit is not required to refer the actions (or failures to act) listed in this Section 30.4.5.3.2 to the Commission as Market Violations, because they have: (i) already been reported by the ISO as a Market Problem under Section 3.5.1 of the ISO Services Tariff; and/or (ii) because they pertain to actions or failures that: (a) are expressly set forth in the ISO's Tariffs; (b) involve objectively identifiable behavior; and (c) trigger a sanction or other consequence

that is expressly set forth in the ISO Tariffs and that is ultimately appealable to the Commission. The actions (or failures to act) that are exempt from mandatory referral to the Commission are:

30.4.5.3.2.1 failure to meet a Contract or Non-Contract CRIS MW Commitment pursuant to Sections 40.13.11.1.1 and 40.13.11.1.2 of Attachment HH to the ISO OATT that results in a charge or other a sanction under Section 40.13.11.1.3 of Attachment HH of the ISO OATT;

30.4.5.3.2.2 Black Start performance that results in reduction or forfeitures of payments under Rate Schedule 5 to the ISO Services Tariff;

30.4.5.3.2.3 any failure by the ISO to meet the deadlines for completing System Impact Studies, or any failure by a Transmission Owner to meet the deadlines for completing Facilities Studies, under Sections 3.7 and 4.5 of the ISO OATT that results in the filing of a notice and/or the imposition of sanctions under those provisions;

30.4.5.3.2.4 failure of a Market Party to comply with the ISO's creditworthiness requirements set forth in Attachment K of the ISO Services tariff, or other action, that triggers sanctions under Section 7.5 of the ISO Services Tariff or Section 2.7.5 of the ISO OATT, specifically: (i) failure of a Market Party to make timely payment under Section 7.2.2 of the ISO Services Tariff or Section 2.7.3.2 of the ISO OATT that triggers a sanction under Sections 7.5.3(i) or 7.5.3(iv) of the ISO Services Tariff, or Sections 2.7.5.3(i), 2.7.5.3(iv), or 2.7.5.4 of the ISO OATT; (ii) failure of a Market Party to comply with a demand for additional credit support under Section 26.6 of Attachment K of the ISO Services Tariff that triggers a

sanction under Section 7.5.3(i) of the ISO Services Tariff or Section 2.7.5.3(i) of the ISO OATT; (iii) failure of a Market Party to cure a default in another ISO/RTO market under Sections 7.5.3(iii) of the ISO Services Tariff, or Section 2.7.5.3(iii) of the ISO OATT that triggers a sanction under either of those tariff provisions; (iv) failure of a Market Party that has entered into a Prepayment Agreement with the ISO under Appendix K-1 to Attachment K to the ISO Services Tariff to make payment in accordance with the terms of the Prepayment Agreement that triggers a sanction under the Prepayment Agreement or 7.5.3(i) of the ISO Services Tariff; and (v) failure of a Market Party to make timely payment on two occasions within a rolling twelve month period under Section 7.5.3(iv) of the ISO Services Tariff, or Section 2.7.5.3(iv) of the ISO OATT that triggers a sanction under either of those provisions.

30.4.5.3.2.5 bidding in a manner that results in a penalty under Section 23.4.3.3.4 of the Market Mitigation Measures.

30.4.5.3.2.6 submission of inaccurate fuel type information into the Day-Ahead Market that results in a penalty under Section 23.4.3.3.3.3 of the Market Mitigation Measures.

30.4.5.3.2.7 submission of inaccurate fuel type and/or fuel price information into the Real-Time Market that results in a penalty under Section 23.4.3.3.3.4 of the Market Mitigation Measures.

30.4.5.3.2.8 notification to the ISO by an Installed Capacity Supplier of a failure to establish by December 1 of a subject Capability Year, or thereafter to maintain, an operating plan and related supply, transportation, and/or replenishment

agreements for the duration of the Winter Performance Period in a subject Capability Year in accordance with Sections 5.12.15 and 5.12.12.3 of the ISO Services Tariff.

To the extent the above list enumerates specific Tariff provisions, the exclusions specified above shall also apply to re-numbered and/or successor provisions thereto. The Market Monitoring Unit is not precluded from referring any of the activities listed above to the Commission.

30.4.5.4 Identify and notify the Commission staff of perceived market design flaws that could be effectively remedied by rule or tariff changes.

30.4.5.4.1 In compliance with § 35.28(g)(3)(v) of the Commission's regulations (or any successor provisions thereto) the Market Monitoring Unit shall submit a referral to the Commission when the Market Monitoring Unit has reason to believe that a market design flaw exists, that the Market Monitoring Unit believes could effectively be remedied by rule or tariff changes.

30.4.5.4.1.1 If the Market Monitoring Unit believes broader dissemination of the possible market design flaw, and its recommendation could lead to exploitation, the Market Monitoring Unit shall limit distribution of its referral to the ISO and to the Commission. The referral shall explain why further dissemination should be avoided.

30.4.5.4.1.2 Following referral of a possible market design flaw, the Market Monitoring Unit shall continue to provide to the Commission additional information regarding the perceived market design flaw, its effects on the market, any additional or modified observations concerning the Market Monitoring Unit's

proposed market rule or tariff change, any recommendations made by the Market Monitoring Unit to the ISO, its stakeholders, Market Parties or state public service commissions regarding the perceived market design flaw, and any actions taken by the ISO regarding the perceived market design flaw.

30.4.6 Market Monitoring Unit Responsibilities Set Forth Elsewhere in the ISO's Tariffs

30.4.6.1 Supremacy of (Attachment O)

Provisions addressing the Market Monitoring Unit, its responsibilities and its authority, have been centralized in Attachment O. However, provisions that address the Market Monitoring Unit can also be found in the Market Mitigation Measures that are set forth in Attachment H to the ISO Services Tariff, and elsewhere in the ISO's Tariffs. In the event of any inconsistency between the provisions of Attachment O and any other provision of the ISO OATT, the ISO Services Tariff, or any of their attachments and schedules, with regard to the Market Monitoring Unit, its responsibilities and its authority, the provisions of Attachment O shall control.

30.4.6.2 Market Monitoring Unit responsibilities set forth in the Market Mitigation Measures

30.4.6.2.1 The ISO and its Market Monitoring Unit shall monitor the markets the ISO administers for conduct that the ISO or the Market Monitoring Unit determine constitutes an abuse of market power but that does not trigger the thresholds specified in the Market Mitigation Measures for the imposition of mitigation measures by the ISO. If the ISO identifies or is made aware of any such conduct, and in particular conduct exceeding the thresholds for presumptive market effects specified in Section 23.3.2.3 of the Market Mitigation Measures, it

shall make a filing under § 205 of the Federal Power Act, 16 U.S.C. § 824d (1999) ("§ 205") with the Commission requesting authorization to apply appropriate mitigation measures. Any such filing shall identify the particular conduct the ISO believes warrants mitigation, shall propose a specific mitigation measure for the conduct, shall incorporate or address the recommendation of its Market Monitoring Unit, and shall set forth the ISO's justification for imposing that mitigation measure. The Market Monitoring Unit's reporting obligations are specified in Sections 30.4.5.3 and 30.4.5.4 of Attachment O. *See* Market Mitigation Measures Section 23.1.2.

30.4.6.2.2 The ISO and the Market Monitoring Unit shall monitor the ISO Administered Markets for other categories of conduct, whether by a single firm or by multiple firms acting in concert, that have material effects on prices or guarantee payments in an ISO Administered Market. *See* Market Mitigation Measures Section 23.2.4.4.

30.4.6.2.3 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, over a time period of at least one week, submitted inaccurate fuel type or fuel price information that was, taken as a whole, biased in the Market Party's favor, *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 the 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 durations specified in Sections 23.3.1.4.6.9.1, 23.3.1.4.6.9.2, and

23.3.1.4.6.9.3 of the Mitigation Measures. *See* Section 23.3.1.4.6.9 of the Market Mitigation Measures

30.4.6.2.4 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. *See* Market Mitigation Measures Section 23.3.2.2.1.

30.4.6.2.5 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. *See* Market Mitigation Measures Section 23.3.2.2.2.

30.4.6.2.6 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 the Market Mitigation Measures, contact the Market Party engaging in the identified conduct to request an explanation of the conduct. 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 of the Market Mitigation Measures 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. 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. Market Parties shall ensure that the information they submit to the ISO, including but not limited to fuel price, fuel type and opportunity cost information, is accurate. Except as set forth in Section 23.3.1.4.6.8 of the Market Mitigation Measures, 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 of the Market Mitigation Measures, the ISO may not retroactively revise a reference level to reflect accurate opportunity costs if a Market Party or its representative did not timely submit accurate opportunity 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. 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 before the ISO issues its decision or determination to the Market Party. 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 of the Market Mitigation Measures for that Market Party's Generator(s) or Aggregation(s). If cost data or other information submitted by a Market Party indicates to the satisfaction of the ISO that the reference levels for that Market Party's Generator(s) or Aggregation(s) 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 recommendation 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 reference levels addressed pursuant to the terms of Section 23.3.3.1.4 of the Market Mitigation Measures shall be implemented on a going-forward basis commencing no earlier than the date that the Market Party's consultation request is received. *See* Market Mitigation Measures Sections 23.3.3.1.1 through 23.3.3.1.5.

30.4.6.2.7 With regard to a Market Party's request for consultation that satisfies the requirements of Sections 23.3.3.3.1.4 and 23.3.3.3.1.7 of the Market Mitigation Measures, and consistent with the duties assigned to the ISO in Section 23.3.3.3.1.7.1 of the Market Mitigation Measures, a preliminary determination by the ISO regarding the Market Party's consultation request shall be provided to the Market Monitoring Unit for its review and the ISO shall consider the Market Monitoring Unit's recommendations in reaching its decision. *See* Market Mitigation Measures Section 23.3.3.3.1.7.1 and 23.3.3.3.1.7.2.

30.4.6.2.8 Review pursuant to Market Mitigation Measures Section 23.4.5.4.3

(a) Reasonably in advance of the deadline for submitting offers in an External Reconfiguration Market and in accordance with the deadlines specified in ISO Procedures, the Responsible Market Party for External Sale UCAP may request the ISO to provide a projection of ICAP Spot Auction clearing prices for a Mitigated Capacity Zone over the Comparison Period for the External Reconfiguration Market. Prior to completing its projection of ICAP Spot Auction clearing prices for a Mitigated Capacity Zone over the Comparison Period for the External Reconfiguration Market, the ISO shall consult with the Market Monitoring Unit regarding such price projection. *See* Market Mitigation Measures Section 23.4.5.4.3(a).

(b) At least fifteen Business Days in advance of the opening of the ICAP Spot Market Auction, the Responsible Market Party for a Behind-the-Meter Net Generation Resource may request the ISO to make a determination regarding physical withholding that the sale of Net Unforced Capacity in a Mitigated Capacity Zone to its Host Load does not constitute physical withholding. Prior to reaching its decision on such a request, the ISO shall provide its preliminary determination to the Market Monitoring Unit for review and comment. *See* Market Mitigation Measures Section 23.4.5.4.3(b).

30.4.6.2.9 Prior to reaching its decision regarding whether the presumption of control of Unforced Capacity has been rebutted, the ISO shall provide its preliminary determination to the Market Monitoring Unit for review and comment. *See* Market Mitigation Measures Section 23.4.5.5.

30.4.6.2.10 Any proposal or decision by a Market Participant to retire or otherwise remove an Installed Capacity Supplier from a Mitigated Capacity Zone Unforced Capacity market, or to de-rate the amount of Installed Capacity available from such supplier, may be subject to audit and review by the ISO if the ISO determines that such action could reasonably be expected to affect Market-Clearing Prices in one or more ICAP Spot Market Auctions for a Mitigated Capacity Zone subsequent to such action; provided, however, no audit and review shall be necessary if the Installed Capacity Supplier is a Generator that is being retired or removed from a Mitigated Capacity Zone as the result of a Forced Outage that began on or after the effective date of the amendments to Section 23.4.5.6.1 of this Services Tariff that was determined by the ISO to be a Catastrophic Failure.

The ISO's audit or review of any proposal or decision by a Market Participant to retire or otherwise remove an Installed Capacity Supplier from a Mitigated Capacity Zone Unforced Capacity market, or to de-rate the amount of Installed Capacity available from such supplier (including a review the ISO conducts at the request of a Market Participant before it submits a proposal or makes a decision or a review the NYISO conducts in conjunction with the Short-Term Reliability Process), will consider the rationale offered by the Market Participant to support its proposal or decision. Such an audit or review shall assess whether the Market Participant's proposal or decision has a legitimate economic justification, which may include the economics of complying with regulatory requirements, or is based on an effort to withhold Installed Capacity

physically in order to affect prices. The ISO's audit or review is conducted based on the expectation that a Market Participant's decision to retire or otherwise remove an Installed Capacity Supplier from a Mitigated Capacity Zone, or to de-rate the amount of Installed Capacity available from such supplier, accounts for the information available to that Market Participant at (or before) the time its decision is made on the "decision date" (*see, e.g.,* Sections 23.4.5.6.4.2.1 and 23.4.5.6.4.2.2.1 of this Services Tariff) specified by the Market Participant. A Market Participant may offer publicly available information and other information available to the Market Participant to support its proposal or decision.

The ISO shall provide the preliminary results of its audit or review to the Market Monitoring Unit for its review and comment. *See* Market Mitigation Measures Section 23.4.5.6.

30.4.6.2.11 Any reclassification of a an Installed Capacity Supplier that is a Generator in a Mitigated Capacity Zone from a Forced Outage that began on or after the effective date of Section 23.4.5.6.2 of this Services Tariff to an ICAP Ineligible Forced Outage by a Market Participant or otherwise, pursuant to the terms of Section 5.18.2.1 of this Services Tariff, may be subject to audit and review by the ISO if the ISO determines that such reclassification could reasonably be expected to affect the Market-Clearing Price in one or more ICAP Spot Market Auctions for a Mitigated Capacity Zone in which the Generator(s) that is the subject of the reclassification is located, subsequent to such action; provided, however, if the Market Participant's Generator experienced the Forced Outage as a result of a Catastrophic Failure, the reclassification of a Generator in a Mitigated Capacity

Zone from a Forced Outage to an ICAP Ineligible Forced Outage shall not be subject to audit and review pursuant to Section 23.4.5.6.2 of this Services Tariff.

The audit and review pursuant to the above paragraph shall assess whether the reclassification of the Generator in a Mitigated Capacity Zone from a Forced Outage to an ICAP Ineligible Forced Outage had a legitimate economic justification or is based on an effort to withhold Installed Capacity physically in order to affect prices. A Market Participant may offer publicly available information and other information available to the Market Participant to justify the reclassification.

The ISO shall provide the preliminary results of its audit or review to the Market Monitoring Unit for its review and comment.

The audit and review pursuant to Section 23.4.5.6.2.1 of this Services Tariff shall be deferred by the ISO beyond the time period established in ISO Procedures for the audit and review until the ISO's receipt of data pursuant to Section 23.4.5.6.2.2 if the Generator was in a Forced Outage for at least 180 days before the reclassification and one or more Exceptional Circumstances delayed the acquisition of data necessary for the ISO's audit and review. If, at the time the ISO acquires the necessary data, the Market Participant has Commenced Repair of the Generator, or the Generator is determined by the ISO to have had a Catastrophic Failure, the Market Participant shall not be subject to an audit and review pursuant to Section 23.4.5.6.2.1 of this Services Tariff. The ISO shall provide the preliminary results of its audit or review to the Market Monitoring Unit for its review and comment.

30.4.6.2.12 The ISO shall consult with the Market Monitoring Unit when it is determining pursuant to Section 23.4.5.6.4.2.2 of this Services Tariff whether there is a point in the process of deactivating a Generator after which the deactivation process will become, essentially and practicably, irreversible.

30.4.6.2.13 When evaluating an Examined Facility or NCZ Examined Project pursuant to Section 23.4.5.7 of the Market Mitigation Measures, the ISO shall seek comment from the Market Monitoring Unit on matters relating to the determination of price projections, cost calculations, and the methodology the ISO will use to project net Energy and Ancillary Services for each UDR project, and the inputs used to perform the calculation the ISO's draft list of recommended Exempt Renewable Technologies and the basis for the recommendation; requests pursuant to Section 23.4.5.7.14.1.2(e)(C) regarding whether a "contract" (as defined in Section 23.4.5.7.14.2(e) would make it ineligible to obtain or (if previously granted) retain a Self Supply Exemption. As required by Section 23.4.5.7 of Attachment H to this Services Tariff, the Market Monitoring Unit shall prepare a written report discussing factors that affect the ISO's mitigation exemption and Offer Floor determinations, and confirming whether the ISO's Offer Floor and exemption determinations and calculations conducted pursuant to Sections 23.4.5.7.2 and 23.4.5.7.6, the NYISO's determination of eligible or ineligible for an exemption pursuant to Section 23.4.5.7.9, 23.4.5.7.13, and 23.4.5.7.14 were conducted in accordance with the terms of the Services Tariff, and if not, identifying the flaws inherent in the ISO's approach. This report shall be presented concurrent with the ISO's posting of its mitigation exemption and

Offer Floor determinations. Pursuant to Section 23.4.5.7.8 of the Market Mitigation Measures, the ISO shall also consult with the Market Monitoring Unit when evaluating whether any existing or proposed Generator or UDR project in a Mitigated Capacity Zone, except New York City, has Commenced Construction, and determinations of whether it shall be exempted from an Offer Floor under that Section. Prior to the ISO making an exemption determination pursuant to Section 23.4.5.7.8, the Market Monitoring Unit shall provide the ISO a written opinion and recommendation. The Market Monitoring Unit shall also provide a public report on its assessment of an ISO determination that an existing or proposed Generator or UDR project is exempt from an Offer Floor under Section 23.4.5.7.8. *See* Market Mitigation Measures Section 23.4.5.7.

30.4.6.2.14 RMR Generator Energy and Ancillary Service Market Participation Rules.

If a new operating constraint arises while a Generator that is required to comply with the bidding requirements in Section 30.6 of the ISO Services Tariff is an Interim Service Provider that prevents the Market Party from offering all or a portion of the Generator's capability via an ISO-committed flexible Bid, the Market Party shall promptly inform the ISO of the change, shall provide all documentation requested by the ISO or by the Market Monitoring Unit, and shall permit the ISO and/or the Market Monitoring Unit to inspect the affected Generator (including all requested plant records) on five days prior notice. *See* Market Mitigation Measures Section 23.6.1.1.3.

The ISO, in consultation with the Market Monitoring Unit, may review and update an Interim Service Provider's reference levels. The Generator Owner

may propose updates to its Interim Service Provider's reference levels. The ISO shall make the ultimate determination with regard to each reference level. *See* Market Mitigation Measures Section 23.6.2.2.

In advance of the execution of an RMR Agreement, the ISO, in consultation with the Market Monitoring Unit and the Generator Owner, shall review and update the reference levels for each affected Generator. The ISO shall make the ultimate determination with regard to each reference level. *See* Market Mitigation Measures Section 23.6.2.3.

If a possible RMR Generator or Interim Service Provider faces operational constraints the ISO, in consultation with the Market Monitoring Unit and the Generator Owner, will develop reference levels that will permit the Generator to operate consistent with the identified constraints, while ensuring that the Generator will be available (a) to resolve the Reliability Need the Generator is being retained to address, and (b) for economic commitment when appropriate. *See* Market Mitigation Measures Section 23.6.2.3.1.

If a physical change to the RMR Generator occurs that alters the RMR Generator's capabilities (*e.g.*, damage to the generator or Capital Expenditures that alter an RMR Generator's capabilities), then the ISO shall determine revised reference levels in consultation with the Market Monitoring Unit and the Generator Owner. *See* Market Mitigation Measures Section 23.6.2.4.4.

The ISO and the Generator Owner, in consultation with the Market Monitoring Unit, may mutually agree to a reference level change that they expect will better reflect an RMR Generator's actual operating characteristics or variable

costs. *See* Market Mitigation Measures Section 23.6.2.4.5.

30.4.6.3 Market Monitoring Unit responsibilities set forth in the ISO Services Tariff

30.4.6.3.1 The ICAP Demand Curve periodic review schedule and procedures shall provide an opportunity for the Market Monitoring Unit to review and comment on the draft request for proposals, the independent consultant's report, and the ISO's proposed ICAP Demand Curves. *See* ISO Services Tariff Sections 5.14.1.2.1.5 and 5.14.1.2.2.4.5.

30.4.6.3.2 The new capacity zone periodic review shall provide an opportunity for the Market Monitoring Unit to review and comment on the NCZ Study, and any proposed NCZ tariff revisions. See ISO Services Tariff Sections 5.16.1.3 and 5.16.4.

30.4.6.4 Market Monitoring Unit responsibilities set forth in the Rate Schedules to the ISO Services Tariff.

30.4.6.4.1 Responsibilities related to the Regulation Service Demand Curve

In order to respond to operational or reliability problems that arise in real-time, the ISO may procure Regulation Service at a quantity and/or price point different than those specified in Section 15.3.7 of Rate Schedule 3 to the ISO Services Tariff. 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 90 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.

After the first year the Regulation Service Demand Curve is in place, the ISO shall perform periodic reviews, subject to the scope requirement specified in Section 15.3.7 of Rate Schedule 3 to the ISO Services Tariff, 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. *See* Section 15.3.7 of Rate Schedule 3 to the ISO Services Tariff.

30.4.6.4.2 Responsibilities related to the Operating Reserves Demand Curves and Scarcity Reserve Demand Curve

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 in Section 15.4.7 of Rate Schedule 4 to the ISO Services Tariff. 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 in Section 15.4.7 of Rate Schedule 4 to the ISO Services Tariff in order to avoid future operational or reliability problems it may temporarily modify them for a period of up to 90 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.

After the first year the Operating Reserves Demand Curves are in place, the ISO shall perform periodic reviews, subject to the scope requirement specified in Section 15.4.7 of Rate Schedule 4 to the ISO Services Tariff, 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. *See* Section 15.4.7 of Rate Schedule 4 to the ISO Services Tariff.

30.4.6.5 Market Monitoring Unit responsibilities set forth in the Attachments to the ISO Services Tariff (other than the Market Mitigation Measures).

30.4.6.5.1 Responsibilities related to Transmission Shortage Cost

The ISO may periodically evaluate the Transmission Shortage Cost to determine whether it is necessary to modify the Transmission Shortage Cost to avoid future operational or reliability problems. The ISO will consult with its Market Monitoring Unit after it conducts this evaluation.

If the ISO determines that it is necessary to modify the Transmission Shortage Cost in order to avoid future operational or reliability problems the resolution of which would otherwise require recurring operator intervention outside normal market scheduling procedures, in order to avoid among other reliability issues, a violation of NERC Interconnection Reliability Operating Limits or System Operating Limits, it may temporarily modify it for a period of up to 90 days, provided however the ISO shall file such change with the Commission pursuant to § 205 of the Federal Power Act within 45 days of such modification. If circumstances reasonably allow, the

ISO will consult with its Market Monitoring Unit, the Business Issues Committee, the Commission, and the PSC before implementing any such modification. In all circumstances, the ISO will consult with those entities as soon as reasonably possible after implementing a temporary modification and shall explain the reasons for the change. *See* Section 17.1.4 of Attachment B to the ISO Services Tariff.

30.4.6.6 Market Monitoring Unit responsibilities set forth in the ISO OATT

30.4.6.7 Market Monitoring Unit responsibilities set forth in the Rate Schedules to the ISO OATT

30.4.6.8 Market Monitoring Unit responsibilities set forth in the Attachments to the ISO OATT

30.4.6.8.1 Responsibilities related to implementing new scheduling path prohibitions

If the ISO, acting in consultation with its Market Monitoring Unit, identifies transmission scheduling paths that are being used to schedule External Transactions in a manner that is not consistent with the manner in which power is actually expected to flow, the ISO may submit a compliance filing in FERC Docket No. ER13-780 proposing to expand the list of prohibited scheduling paths included in Section 16.3.3.8 of the ISO OATT. The ISO's compliance filing will include, or be accompanied by, a discussion of the Market Monitoring Unit's position regarding the ISO's proposal to add a new prohibited scheduling path or new prohibited scheduling paths. The Market Monitoring Unit's position may be explained in the ISO's filing letter, be set forth in an accompanying affidavit, or be submitted by the Market Monitoring Unit as a companion filing or as comments on the ISO's compliance filing in Docket No. ER13-780. *See* Section 16.3.3.8 of Attachment J to the ISO OATT.

30.4.6.8.2 Responsibilities related to the draft Reliability Needs Assessment

Following the Management Committee vote, the draft Reliability Needs Assessment (RNA), with working group, Operating Committee, and Management Committee input, will be forwarded to the ISO Board for review and action. Concurrently, the draft RNA will be provided to the Market Monitoring Unit for its review and consideration of whether market rules changes are necessary to address an identified failure, if any, in one of the ISO's competitive markets. *See* Section 31.2.3.2 of Attachment Y to the ISO OATT.

30.4.6.8.3 Responsibilities related to the draft Comprehensive Reliability Plan

Following the Management Committee vote, the draft Comprehensive Reliability Plan (CRP), with working group, Operating Committee, and Management Committee input, will be forwarded to the ISO Board for review and action. Concurrently, the draft CRP will also be provided to the Market Monitoring Unit for its review and consideration of whether market rule changes are necessary to address an identified failure, if any, in one of the ISO's competitive markets. *See* Section 31.2.7.2 of Attachment Y to the ISO OATT.

30.4.6.8.4 Responsibilities related to the draft System & Resource Outlook

Following the Management Committee vote, the draft System & Resource Outlook, with Business Issues Committee and Management Committee input, will be forwarded to the ISO Board for review and action. Concurrently, the draft System & Resource Outlook will be provided to the Market Monitoring Unit for its review and consideration. *See*, as applicable, Section 31.3.1.8.2 or 31.6.7.1.2 of Attachment Y to the ISO OATT.

30.4.6.8.5 Responsibilities related to the draft Public Policy Transmission Planning Report

The ISO will provide the draft Public Policy Transmission Planning Report to the Market

Monitoring Unit for its review and consideration of any impact on the ISO-administered markets of regulated transmission solutions proposed to satisfy a Public Policy Transmission Need. *See* Sections 31.4.9 and 31.4.10.1 of Attachment Y to the ISO OATT. The Market Monitoring Unit's evaluation will be provided to the Management Committee before the Management Committee's advisory vote. *See* Section 31.4.10.1 of Attachment Y. Following the Management Committee vote, the draft Public Policy Transmission Planning Report, with Business Issues Committee and Management Committee input, will be forwarded to the ISO Board for review and action. Concurrent with the submission to the ISO Board of the draft Public Policy Transmission Planning Report, the Market Monitoring Unit's evaluation will be provided to the ISO Board. *See* Section 31.4.7 of Attachment Y to the ISO OATT.

30.4.6.8.6 Responsibilities Related to Market Monitoring Unit Review of Reliability Must Run Costs and RMR Avoidable Cost Determinations

The ISO shall seek comments from the Market Monitoring Unit on matters relating to the inputs and the calculations the ISO performed pursuant to Section 38.8 of Attachment FF of the ISO OATT. *See* Section 38.8.2 of Attachment FF of the ISO OATT.

The ISO shall seek comments from the Market Monitoring Unit on its review of Proposed Additional Costs and its determinations of Substantiated Additional Costs under Section 38.16 of Attachment FF of the ISO OATT. *See* Section 38.16.2.2 of Attachment FF of the ISO OATT.

Concurrent with the ISO or a Generator filing with the Commission an RMR Agreement pursuant to Sections 38.11.3, 38.11.4 or 38.11.5 of Attachment FF to the ISO OATT, the Market Monitoring Unit shall publish a report. The report shall review the ISO's determination of the highest net present value offer (or more than one offer) to provide RMR service in accordance

with Sections 38.8, 38.9 and 38.10 of Attachment FF to the ISO OATT. In the event that cost alone did not provide for a clear delineation between two or more RMR Service Offers, the report shall also review the ISO's consideration of the Generator Owner's proposed changes to the *Form of Reliability Must Run Agreement* and the operational, performance and market impacts, and the size of the Generators. If the RMR Agreement contains RMR Avoidable Costs and an Availability and Performance Rate, the report shall also review the inputs to, and ISO's calculation of, the RMR Avoidable Costs and the Availability and Performance Rate. *See* Section 38.18.3 of Attachment FF to the ISO OATT.

30.4.6.8.7 Responsibilities related to the draft Long-Term Transmission Planning Report

The ISO will provide the draft Long-Term Transmission Planning Report to the Market Monitoring Unit for its review and consideration of the impacts on the ISO-administered wholesale markets of the Long-Term Transmission Project recommended for selection. *See* Section 31.6.11.3 of Attachment Y to the ISO OATT. The Market Monitoring Unit will provide the results of its review to the Management Committee before the Management Committee's advisory vote. *See* Section 31.6.11.3 of Attachment Y to the ISO OATT. Following the Management Committee vote, the draft Long-Term Transmission Planning Report, with Business Issues Committee and Management Committee input, will be forwarded to the ISO Board for review and action. Concurrent with the submission to the ISO Board of the draft Long-Term Transmission Planning Report, the Market Monitoring Unit will provide the results of its review to the ISO Board. *See* Section 31.6.11.4 of Attachment Y to the ISO OATT.

30.4.6.9 Market Monitoring Unit responsibilities set forth in other documents that have been formally filed with the Commission

30.4.6.10 Market Monitoring Unit responsibilities set forth in the Form of Reliability Must Run Agreement, Appendix C to Attachment FF of the ISO OATT

The ISO and the Market Monitoring Unit shall monitor deviations from each RMR Generator's historic planned outage schedules. Owner shall promptly respond to ISO and Market Monitoring Unit requests for explanations, information and data regarding or supporting outage schedules. *See* Section 7.1.3 of the *Form of Reliability Must Run Agreement.*

The ISO and the Market Monitoring Unit shall monitor deviations from each RMR Generator's historic forced outage rate. Owner shall promptly respond to ISO and Market Monitoring Unit requests for explanations, information and data regarding or supporting forced outages, including the time required to return from a Forced Outage. *See* Section 7.2.2 of the *Form of Reliability Must Run Agreement.*

30.4.6.11 Additional Market Monitoring Unit responsibilities related to Reliability Must Run Agreements

The Market Monitoring Unit shall review any Owner-Developed Rate that is filed with the Commission as described in Section 4.5 of the *Form of Reliability Must Run Agreement*. The Market Monitoring Unit shall intervene and participate in Commission proceedings concerning such filings. It shall submit, as appropriate, comments or a protest in such a proceeding describing its review and informing the Commission of whether it has found a proposed Owner Developed Rate to be consistent with, or in excess of, an RMR Generator's full cost of service. The Market Monitoring Unit shall also inform the Commission of whether: (i) it believes the proposed Owner Developed Rate, including its terms and conditions of service, is or is not just and reasonable; and (ii) it has any other concerns with the proposed Owner Developed Rate.

30.4.7 Availability of Data and Resources to Market Monitoring Unit

30.4.7.1 The ISO shall ensure that the Market Monitoring Unit has sufficient access to ISO resources, personnel and market data to enable the Market Monitoring Unit to carry out its functions under Attachment O. Consistent with Section 30.6.1 of Attachment O, the Market Monitoring Unit shall have complete access to the ISO's databases of market information.

30.4.7.2 Any data created by the Market Monitoring Unit, including but not limited to reconfiguration of the ISO's data, will be kept within the exclusive control of the Market Monitoring Unit. The Market Monitoring Unit may share the data it creates, subject to the limitations on distribution of and obligation to protect the confidentiality of Protected Information that are contained in Attachment O, the ISO Services Tariff, and the ISO's Code of Conduct.

30.4.7.3 Where data outside the ISO's geographic footprint would be helpful to the Market Monitoring Unit in carrying out its duties, the Market Monitoring Unit should seek out that data (with assistance from the ISO, where appropriate).

30.5 Monitoring Implementation And Responsibilities

30.5.1 Monitoring Methods, Procedures and Resources

30.5.1.1 Adequacy

The Market Monitoring Unit and MMA shall develop and implement methods, procedures, staffing and other resources for achieving the purposes and objectives of Attachment O. Such methods, procedures, staffing and other resources shall be appropriate to realizing the purposes and objectives and effective implementation of Attachment O, and shall be subject to review, modification and approval by the ISO's CEO or the CEO's designee, the COO, where the measures involve the MMA, or by the ISO's Board, where the measures involve the Market Monitoring Unit.

30.5.1.2 Conditions, Functions or Actions Monitored

The monitoring methods, procedures, staffing and other resources shall ensure, to the extent practicable, that the Market Monitoring Unit and the ISO (consistent with the division of duties specified above) are able to achieve the purposes and objectives of Attachment O through review and analysis of conditions, functions or actions affecting the competitiveness, economic efficiency and proper operation of any of the New York Electric Markets, including but not limited to the following, as and to the extent each may be deemed relevant to the purposes and objectives of Attachment O by the Market Monitoring Unit or by the ISO:

30.5.1.2.1 The nature, extent and causes of any undue concentration in the ownership or control of generation or other facilities in or affecting any of the New York Electric Markets;

30.5.1.2.2 Any evidence of or other information relating to collusive or other anticompetitive or inefficient behavior in or affecting any of the New York

Electric Markets;

30.5.1.2.3 The bids or offers submitted to each of the New York Electric Markets administered by the ISO, the evaluation of those bids or offers, and as appropriate the relationship of those bids or offers to marginal or other costs;

30.5.1.2.4 Schedules submitted to the ISO for bilateral or other transactions;

30.5.1.2.5 Unit commitment and dispatch in the New York Control Area;

30.5.1.2.6 The determination and level of LBMPs or other prices in the New York Electric Markets;

30.5.1.2.7 The provision of transmission services in the New York Control Area, including but not limited to auctions and other markets for TCCs;

30.5.1.2.8 The nature and extent, causes of, and costs of and charges for, transmission congestion on the New York State Transmission System or, to the extent practicable, transmission congestion on any other system that affects any of the New York Electric Markets;

30.5.1.2.9 Competitive or other market impacts of tariffs and agreements, or other rules, standards or procedures, governing or affecting any of the New York Electric Markets;

30.5.1.2.10 The need for and the implementation and efficacy of market power mitigation or other remedial measures for competitive or other market defects, including mitigation measures implemented in accordance with the provisions of Attachment O or other mitigation measures that the FERC has authorized or directed the ISO to implement;

30.5.1.2.11 The need for and the implementation and efficacy of appropriate sanctions

or other remedial measures for violations of or other failures to comply with any tariff or services agreement, or any rule, standard or procedure, or any market power mitigation or other remedial measure, to the extent such violation or failure to comply impairs or threatens to impair the competitiveness or economic efficiency of any of the New York Electric Markets;

30.5.1.2.12 To the extent practicable, conditions or events outside the New York Control Area affecting the supply and demand for, and the quantity and price of, products or services sold or to be sold in any of the New York Electric Markets; and

30.5.1.2.13 Such other conditions, functions or actions as may be approved by the CEO or the CEO's designee, the COO, or by the Board (as appropriate).

30.5.3 Legal Advice

The Market Monitoring Unit and MMA may consult legal counsel for the ISO for advice on antitrust, regulatory or other legal issues pertinent to Attachment O.

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.

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.

30.7 Performance Indices and screens

30.7.1 Development of Indices and Screens

The MMA or the Market Monitoring Unit, with due consideration of the proposals and comments of Market Parties and other interested parties submitted as specified below, with the approval of the CEO or the CEO's designee, the COO, and the Market Monitoring Unit (for indices and screens developed by the MMA), or subject to review and comment by the ISO and review and approval by the Board (for indices and screens developed by the Market Monitoring Unit), shall develop, adopt and refine on the basis of experience with their application, such indices or other screens for reviewing the data or other information collected in connection with the implementation of Attachment O, or the ISO's Market Mitigation Measures, as the MMA or Market Monitoring Unit deem appropriate. All proposed or adopted indices and screens shall be described in the ISO Procedures and shall be made available through the ISO web site or comparable means, provided and to the extent that any such description does not provide details of the standards, criteria or thresholds for evaluating such data or information that would facilitate conduct inconsistent with the competitiveness or economic efficiency of any of the New York Electric Markets.

30.7.2 Consultation with Market Parties

In connection with the development of indices and screens as specified above, Market Parties or other interested parties may submit proposed indices or screens for review of the data or other information collected in connection with the implementation of Attachment O, along with any justification for the adoption thereof, to the ISO or Market Monitoring Unit for consideration and adoption if and to the extent appropriate.

30.7.3 Use of Indices and Screens

As much as practicable, the MMA and the Market Monitoring Unit shall review data or other information collected in connection with implementation of Attachment O and the Market Mitigation Measures in accordance with the indices or screens adopted as specified above; provided, however, that nothing herein shall be deemed to prevent the ISO or the Market Monitoring Unit from conducting such further or different review or evaluation of such data or information as appropriate for the effective implementation of Attachment O.

30.8 Market Power Mitigation Measures

30.8.1 Review and Regulatory Approval

A mitigation measure developed as specified below and recommended by the Market Monitoring Unit and the CEO or the CEO's designee, the COO, shall, with the review and approval of the Board, and in accordance with the ISO procedures applicable to tariff filings, be submitted by the ISO to the FERC for approval as an addendum to Attachment O or to the Market Mitigation Measures, and shall be provided as an informational submission to the other Interested Government Agencies. A market power mitigation measure shall become effective and available for use by the ISO as soon as practicable upon FERC approval.

30.8.2 Development of Mitigation Measures

The Market Monitoring Unit, with the assistance of the MMA and the approval of the Reliability and Markets Committee of the Board (or any successor committee thereto), shall propose, and refine or revise as may be appropriate in consideration of the comments of Market Parties and other interested parties and market experience, measures for the mitigation of market power in any of the New York Energy Markets administered by the ISO, and standards for determining the actual or potential existence of market power requiring the application of such measures. A description of all effective and proposed mitigation measures and of the standards for the application of each such measure shall be made available through the ISO web site or comparable means. Except for mitigation measures that the ISO is required to file in accordance with Section 23.3.2.3 of the Market Mitigation Measures, prior to the submission of any market power mitigation measure to the FERC for approval as specified above, the ISO shall notify the Market Parties and other interested parties and provide an opportunity for comment on the proposed measure, and shall submit such measure for review and vote by the Management

Committee in accordance with the procedures applicable to tariff filings.

30.8.3 Implementation of Mitigation Measures

The ISO, as directed and authorized by the CEO or the CEO's designee, the COO, shall implement the mitigation measures developed as specified above and such other mitigation measures as may be authorized or required by the FERC as a result of filings or other submissions by Market Parties or other interested parties or otherwise. The Market Monitoring Unit may participate in the implementation of mitigation measures to the extent permitted in Section 30.4.4 of Attachment O.

30.9 Complaints and Requests for Investigations

Any Market Party or other interested person or entity may at any time submit information to the Market Monitoring Unit concerning any matter relevant to the responsibilities of the Market Monitoring Unit under Attachment O, or may submit a request to the Market Monitoring Unit for the Market Monitoring Unit to conduct an investigation, or take any other action contemplated by Attachment O. Such submissions or requests may be made on a confidential basis. The Market Monitoring Unit's authority to conduct an investigation may be limited by Section 30.4.5.3 of Attachment O. The Market Monitoring Unit shall provide a copy of any such submission or request to the ISO, unless a confidential investigation request addresses the ISO's actions or inaction, and the Market Monitoring Unit determines that it would not be appropriate to reveal the submission or request to the ISO, or that it would not be appropriate to reveal the submission or request to certain ISO personnel or departments. At the time it provides a copy of a confidential submission or request to the ISO, the Market Monitoring Unit may include written instructions to the ISO staff to whom the copy of the submission or request is sent, requiring them to limit their distribution of such submission or request. ISO staff shall abide by any limitation on distribution imposed by the Market Monitoring Unit until the information is made public, or the Market Monitoring Unit, FERC, or FERC staff provide written instructions to the contrary. The MMA shall be available to assist the Market Monitoring Unit's efforts to process or investigate the submissions and requests it receives. The Market Monitoring Unit may request further relevant information available from the submitting Market Party, or from any other person or entity, as a condition of undertaking any further investigation. Following a preliminary review, acting in a timely manner, the Market Monitoring Unit shall decline to take further action, or shall carry out such investigation as it deems appropriate, or as may be required by the

Board acting on its own initiative or at the request of a Market Party or other interested party. The Market Monitoring Unit shall include a summary of its actions or decisions not to act under this Section 30.9 in its annual report to the Board. The summary included in the annual report to the Board need not contain any Protected Information.

30.10 Reports

30.10.1 Annual Reports

The Market Monitoring Unit shall prepare and submit to the Board an annual report on the competitive structure of, market trends in, and performance of, other competitive conditions in or affecting, and the economic efficiency of, the New York Electric Markets. Such report shall include recommendations for the improvement of the New York Electric Markets or of the monitoring, reporting and other functions undertaken pursuant to Attachment O and the Market Mitigation Measures. A copy of the report shall be forwarded by the Board to each of the Interested Government Agencies, with such comments or other remarks as the Board shall deem appropriate. Copies of the report shall be made publicly available by the Board by posting them on the ISO's web site, subject to redaction or other measures necessary for the protection of Protected Information.

30.10.2 Quarterly Reports

In addition to the annual report, the Market Monitoring Unit shall issue three quarterly reports that are less extensive than the annual report. Each quarterly report shall provide timely updates to the annual report, emphasizing issues of concern to the Market Monitoring Unit. Quarterly reports shall be distributed in the same manner as the annual report.

30.10.3 Report on Virtual Bid and Offer Market Design and Rules

The Market Monitoring Unit shall monitor and assess the impact of virtual bids and offers on the competitive structure and performance of, and the economic efficiency of, the ISO Administered Markets. Such monitoring and assessment shall include the effects, if any, of virtual bids and offers on any automated mitigation procedures, or any mitigation measures

specified in Section 23.5 of the Market Mitigation Measures. An assessment of the market impacts of virtual bids and offers shall be included in the annual report required by Section 30.10.1, above, and in a quarterly report when the Market Monitoring Unit deems appropriate.

30.10.4 Reports on Offer Floor or Exemption Determinations

The Market Monitoring Unit shall prepare a written report as described in Section 30.4.6.2.13 confirming whether the ISO's determinations and calculations conducted pursuant to Section 23.4.5.7 were conducted in accordance with the terms of the Services Tariff, and if not, identifying the flaws inherent in the ISO's approach. The Market Monitoring Unit's report shall be presented concurrently with the ISO's posting of the exempt/non-exempt determinations.

30.10.5 Conference Calls

The Market Monitoring Unit shall participate in regular conference calls for the presentation of market data and analyses of the type regularly gathered and prepared by the Market Monitoring Unit under Attachment O, subject to limitations on dissemination of Protected Information. Market Participants, staff of the Commission and the New York Public Service Commission, and representatives of the ISO may attend such conference calls.

30.10.6 Other Reports or Filings

The Market Monitoring Unit, with the assistance of the MMA, where appropriate, shall prepare such other periodic or other reports on any matters within their purview as the Market Monitoring Unit determines are necessary, or as may be requested by the Board, the CEO or the CEO's designee, the COO, or any of the Interested Government Agencies. Unless the Board or the Interested Government Agency requesting such report specifies to the contrary, copies of such reports shall be made publicly available by the Board, subject to redaction or other

measures necessary for the protection of Protected Information. All reasonable fees and expenses for the preparation of reports or other filings relating to the New York Electric Markets that are requested by an Interested Government Agency from the Market Monitoring Unit, or that are requested by an Interested Government Agency from a former Market Monitoring Unit with respect to conditions or conduct occurring in or relating to the period during which the person, persons or entity receiving the request served as the Market Monitoring Unit, shall be borne by the ISO.

30.11 Liability

The liability of the ISO and its directors, officers, employees and agents, and of the Market Monitoring Unit and its directors, officers, employees and agents, for any matter arising under or relating to Attachment O shall be governed by this section. The ISO and its directors, officers, employees and agents, and the Market Monitoring Unit and its directors, officers, employees and agents, shall not be liable to any person or entity for any matter, act or omission described in or contemplated by Attachment O, as the same may be amended or supplemented from time to time, including but not limited to liability for any financial loss, loss of economic advantage, opportunity cost, or actual, direct, indirect or consequential damages of any kind resulting from or attributable to any act or omission of the ISO or the Market Monitoring Unit under Attachment O. The ISO shall indemnify and hold harmless its directors, officers, employees and agents and the Market Monitoring Unit and its directors, officers, employees and agents of and from any and all actions, claims, demands, costs (including any form of damages or other economic loss and all court costs and reasonable attorneys' fees) and liabilities to third parties, arising from or in any way connected with, the implementation or a failure to implement Attachment O, except to the extent that such action, claim, demand, cost or liability results from the willful misconduct of any of the foregoing persons or entities.

30.12 Rights and Remedies

30.12.1

With the exception of the limitation of liability specified in Attachment O, nothing herein shall prevent the ISO or any other person or entity from asserting any rights it may have under the Federal Power Act or any other applicable law, statute, or regulation, including the filing of a petition with or otherwise initiating a proceeding before the FERC regarding any matter which is the subject of Attachment O.

30.12.2

Except as and to the extent otherwise specified in Attachment O, parties with disputes as to the implementation of or compliance with Attachment O may utilize the dispute resolution procedures of the ISO Services Tariff.

30.13 Effective Date

Attachment O shall be effective as of the date it is accepted for filing by the FERC.

31 Attachment P – Coordinated Transaction Scheduling with ISO New England; Actions, Thresholds and Triggers

31.1 Background and Overview

This Attachment P describes the process for pursuing amendments to the ISO tariff in the event that the production cost savings of the ISO's interchange on the NYISO – ISO-NE AC Interface and the Northport/Norwalk Line (both together - "NYISO / ISO-NE Interface"), following the implementation of an Inter-Regional Interchange Scheduling process known as Coordinated Transaction Scheduling ("CTS") on the NYISO/ISO-NE Interface, are not satisfactory. The determination of whether savings are satisfactory will be based on actions, thresholds and triggers described in this Attachment P. The actions, thresholds and triggers described in this Attachment P shall only be measured based upon interchange schedules and estimated schedules at the CTS Enabled Proxy Generator buses on the NYISO / ISO-NE Interface.

If pursuant to the actions, thresholds and triggers described in this Attachment P, the production cost savings of CTS are not satisfactory, and a superior alternative has not become known, the ISO will develop tariff amendments, for filing with the Commission pursuant to Section 31.5, to implement the Inter-Regional Interchange Scheduling process described to the ISO stakeholders in 2011 as Tie Optimization.

If, pursuant to the timetables presented, the ISO determines the thresholds described herein have not triggered, the process for filing amendments to the ISO tariff as described herein ceases, the provisions of this Attachment P become null and void and the ISO continues to implement CTS unless and until future Section 205 filings are pursued to amend CTS.

31.2 The Two-Year Analysis

Within 120 days of the close of the first and second years following the date that CTS as an interface scheduling tool is activated in the ISO and ISO-NE markets, the Market Monitoring Unit (MMU) of the ISO will develop, for presentation to and comment by ISO stakeholders, an analysis, of: (i) the actual bid production cost savings of incremental interchange that would have occurred had the ISOs had an infinite number of zero bids in the CTS process, which utilizes the supply curves and forecasted prices for each market ("Tie Optimization interchange"); and (ii) the actual bid production cost savings of incremental interchange that would have occurred had the ISOs had an infinite number of zero bids in the CTS process, but utilizing actual real-time prices from each market rather than the forecasted prices that were used in the CTS process ("optimal interchange").

The bid production cost savings associated with Tie Optimization interchange as developed in 31.2(i) for the second year following the date that CTS is activated in the ISO and ISO-NE markets, will reveal the "foregone" production cost savings from implementing CTS rather than Tie Optimization, represented in the Section 31.2.1 formula as the term "b." The difference in bid production cost savings between 31.2 (i) and 31.2 (ii) for the second year following the date that CTS is activated in the ISO and ISO-NE markets will reveal the "foregone" bid production cost savings of the Tie Optimization interchange rather than an optimal interchange, represented in the Section 31.2.1 formula as the term "a."

This analysis will be consistent with the presentation Benefits of Coordinating the Interchange Between New York and New England made by Dr. David Patton of the MMU to the ISO's stakeholders on January 21, 2011. The bid production cost savings will be calculated in accordance with, and the operation of the threshold and trigger will be consistent with, the

presentation Potential Trigger to Switch from CTS to TO made by Dr. David Patton of the MMU to the ISO's stakeholders on August 9, 2011.

31.2.1 Using these calculations, the MMU will compute the following ratio:

b/a

If, the ratio b/a is greater than 60% and b is greater than $3 Million, the MMU will advise whether in its opinion the threshold has triggered.

31.3 Improving CTS

31.3.1 If the ratio b/a, developed pursuant to Section 31.2.1 of this Attachment P, is greater than 60% and b is greater than $3 Million, the ISO will declare whether the threshold has triggered considering the input of the MMU and stakeholders.

31.3.2 If the ISO declares the threshold has not triggered the process further described in this Attachment P becomes null and void.

31.3.3 If the ISO declares that the threshold has triggered, the MMU will provide recommendations of adjustments to the design or operation of CTS to improve the production cost savings available from its implementation.

31.3.4 The ISO, considering the input of its stakeholders and the recommendation of the MMU, will develop and implement adjustments to CTS. To the extent tariff revisions are necessary to implement the adjustments to CTS, the ISO will file such revisions with the Commission as a compliance filing in the CTS docket, pursuant to the process described in Section 31.5. If no adjustments to CTS have been identified, the ISO will proceed to develop and file the revisions necessary to amend the ISO Tariffs to implement the Inter-Regional Interchange Scheduling Practice known as Tie Optimization as a compliance filing, pursuant to the process described in Section 31.5.

31.4 The Second Analysis

31.4.1 Within 120 days of the close of the twelve months following the date that the adjustments to CTS, developed under Section 31.3.4, are activated in the ISO and ISO-NE markets, the MMU of the ISO will develop a second analysis, for presentation to and comment by ISO stakeholders. The analysis will be consistent with the analysis described in Section 31.2 of this Attachment P but will develop bid production cost savings for the twelve month period during which the adjustments developed in Section 31.3.4 are in place.

31.4.2 The bid production cost savings associated with Tie Optimization interchange as developed in Section 31.4.1 will reveal the "foregone" bid production cost savings from implementing CTS rather than Tie Optimization, represented in the Section 31.4.3 formula as the term "b." The difference in bid production cost savings between the Tie Optimization interchange and the optimal interchange, as developed in Section 31.4.1, will reveal the "foregone" bid production cost savings of the Tie Optimization interchange rather than optimal interchange, represented in the Section 31.4.3 formula as the term "a."

31.4.3 Using these calculations, the MMU will compute the following ratio:

b/a

If the ratio b/a is greater than 60% and b is greater than $3 Million, the MMU will advise whether in its opinion the threshold has triggered.

31.4.4 If the ratio b/a is greater than 60% and b is greater than $3 Million, the ISO will declare whether the threshold has triggered considering the input of the MMU and their respective stakeholders.

31.4.5 If the ISO declares the threshold has not triggered the process further described in this Attachment P becomes null and void.

31.4.6 If the ISO declares the threshold has triggered, considering the input of the stakeholders and the recommendation of the MMU, the ISO will determine whether a superior alternative has been proposed, considering the input of the stakeholders and the recommendation of the MMU. If the ISO determines a superior alternative has been proposed, the ISO will prepare tariff amendments for a filing with the Commission to implement the superior alternative utilizing the process for amending the NYISO Tariffs set forth in Article 19 of the ISO Agreement and will not pursue the balance of the actions required by this Attachment P.

31.4.7 If the ISO determines a superior alternative has not been proposed, the ISO will proceed to develop and file the revisions necessary to amend the ISO Tariffs to implement the Inter-Regional Interchange Scheduling Practice known as Tie Optimization as a compliance filing, pursuant to the process described in Section 31.5. Tie Optimization was described for Stakeholders in the Design Basis Document for NE/NY Inter-Regional Interchange Scheduling presented at a Business Issues Committee meeting June 1, 2011.

31.5 The Compliance Filing

31.5.1 The filing of Tariff revisions with the Commission pursuant to Sections 31.3.4 and/or Section 31.4.7 shall be pursuant to this section.

The ISO will present to its Board tariff language to implement changes to CTS, developed pursuant to Section 31.3.4, for filing through a compliance filing under Section 205 of the Federal Power Act, following stakeholder review and comment, which comments shall be shared with the ISO Board for use as it deliberates the tariff amendments proposed to be filed with the Commission.

The ISO will present to its Board tariff language to implement Inter-Regional Interchange Scheduling Practice known as Tie Optimization, pursuant to Section 31.4.7, through a compliance filing under Section 205 of the Federal Power Act, following stakeholder review and comment, which comments shall be shared with the ISO Board for its use as it deliberates the tariff amendments proposed to be filed with the Commission.