

Attachment II

2.1 Definitions - A

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

Actual Energy Withdrawals: Energy withdrawals which are either: (1) measured with a revenue-quality real-time meter; (2) assessed (in the case of Load Serving Entities ("LSEs") serving retail customers where withdrawals are not measured by revenue-quality real-time meters) on the basis provided for in a Transmission Owner's retail access program; or (3) calculated (in the case of wholesale customers where withdrawals are not measured by revenue-quality real-time meters), until such time as revenue - quality real-time metering is available on a basis agreed upon by the unmetered wholesale customers.

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

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

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

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

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

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

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

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

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

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

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

Availability: A measure of time that a Generator, transmission line or other facility is or was capable of providing service, whether or not it actually is in-service.

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

Average Coincident Load (“ACL”): The value in each Capability Period calculated for each Special Case Resource, except those that are eligible to report a Provisional Average Coincident

Load, that is equal to the average of the SCR's metered hourly Load that is supplied by the NYS Transmission System and/or the distribution system during the Capability Period SCR Load Zone Peak Hours applicable to such SCR, and computed and reported in accordance with Section 5.12.11.1.1 of this Services Tariff and ISO Procedures. Any Load supported by generation produced from a Local Generator, other behind-the-meter generator, or other supply source located behind the SCR's meter operating during the Capability Period SCR Load Zone Peak Hours may not be included in the SCR's metered Load values reported for the ACL.

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

2.2 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.

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

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, (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 and/or Transmission Owner administered demand response or generation buy-back 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 required to meet Load and reliability Constraints based upon Bids corresponding to the usual measures of Generator 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.

2.4 Definitions - D

DADRP Component: The credit requirement for a Demand Reduction Provider to bid into the Day-Ahead Market, and a component of the Operating Requirement, calculated in accordance with Section 26.4.2 of Attachment K to this Services Tariff.

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 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 that is bid, produced, purchased or sold over a period of time and measured or calculated in Megawatt hours. Demand Reductions offered by a Demand Side Resource as Energy in the LBMP Markets may only be offered in the Day-Ahead Market, and shall be offered only by a Demand Reduction Provider. The same Demand Reduction may not be offered by a Demand Reduction Provider and by a customer as Operating Reserves or Regulation Service.

Demand Reduction Aggregator: A Demand Reduction Provider, qualified pursuant to ISO Procedures, that bids Demand Side Resources of at least 1 MW through contracts with Demand Side Resources and is not a Load Serving Entity.

Demand Reduction Incentive Payment: A payment to Demand Reduction Providers that are scheduled to make Day-Ahead Demand Reductions. The payment shall be equal to the product of: (a) the Day-Ahead hourly LBMP at the applicable Demand Reduction bus; and (b) the lesser of the actual hourly Demand Reduction or the Day-Ahead scheduled hourly Demand Reduction in MW.

Demand Reduction Provider: A Customer that is eligible, pursuant to the relevant ISO Procedures, to bid Demand Side Resources of at least 1 MW as Energy into the Day-Ahead Market. A Demand Reduction Provider can be (i) a Load Serving Entity or (ii) a Demand Reduction Aggregator.

Demand Side Ancillary Service Program (DSASP): An ISO program that allows qualified DSASP Resources to participate in the ISO's Day-Ahead and Real-Time Markets for Operating Reserves and Regulation Service in accordance with the ISO Services Tariff and ISO Procedures.

Demand Side Ancillary Service Program Resource (DSASP Resource): A Demand Side Resource or an aggregation of Demand Side Resources located in the NYCA with at least 1 MW of load reduction that is represented by a point identifier (PTID) and is assigned to a Load Zone or Subzone by the ISO and that is:

- i. Capable of controlling demand in a responsive, measurable and verifiable manner within time limits prescribed by the ISO; and
- ii. Qualified to participate in the ISO's Ancillary Services market as a Supplier of Operating Reserves or Regulation Service pursuant to the ISO Services Tariff and ISO Procedures.

Demand Side Ancillary Service Program Provider (DSASP Provider): A Customer that is eligible, pursuant to the ISO Tariff and ISO Procedures, to offer DSASP Resource(s) as Operating Reserves or Regulation Service in the Day-Ahead or Real-Time Market. A DSASP Provider is responsible for enrolling its DSASP Resource(s), and, when communicating directly with the ISO via telemetry, is responsible for dispatching its DSASP Resource(s).

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, as demonstrated by the performance of a test or through actual operation, averaged over a continuous time period as defined in the ISO Procedures.

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: The sale of TCCs directly to a buyer by the Primary Owner through a non-discriminatory auditable sale conducted on the ISO’s OASIS, in compliance with the requirements and restrictions set forth in Commission Order Nos. 888 et seq. and 889 et seq.

Dispatchable: A bidding mode in which Generators or Demand Side Resources 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 Demand Side Resources must be ISO-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.

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.

DSASP Baseline MW: The value of the Load level of a DSASP resource in the dispatch interval immediately preceding the interval with a non-zero Base Point Signal, where the status of the regulation flag is set to the off condition for either Operating Reserves or Regulation service.

DSASP Component: The credit requirement for a Demand Side Resource to offer Ancillary Services, and a component of the Operating Requirement, calculated in accordance with Section 26.4.2 of Attachment K to this Services Tariff.

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 injection. 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, except for the Generator of a BTM:NG Resource, indicates it expects to be able to reach, 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, or the maximum amount of demand that a Demand Side Resource expects to be able to reduce, 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.

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 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.

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: A Customer of the ISO that has been appointed by a Load Serving Entity and approved by the ISO in accordance with ISO Procedures for the purpose of enabling that Customer to hold all of the rights and obligations associated with Fixed Price TCCs, as provided for in this Services Tariff.

ETCNL TCC: A TCC created when a Transmission Owner with ETCNL exercises its right to convert a megawatt of ETCNL into a TCC pursuant to Section 19.4.1 of Attachment M of the 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: Congestion revenues in the Day-Ahead Market for Energy collected by the ISO that are in excess of its Day-Ahead payment obligations. Excess Congestion Rents may arise if Congestion occurs in the Day-Ahead Market for Energy and if the Day-Ahead Transfer Capability of the transmission system is not exhausted by the set of TCCs and Grandfathered Rights that have been allocated at the completion of the last Centralized TCC Auction.

Existing Transmission Capacity for Native Load ("ETCNL"): Transmission Capacity reserved on a Transmission Owner’s transmission system to serve the Native Load Customers of the current Transmission Owners (as of the filing date of the original ISO Tariff - January 31, 1997). This includes transmission Capacity required: (1) to deliver the output from operating

facilities located out of a Transmission Owner's Transmission District; (2) to deliver power purchased under power supply contracts; and (3) to deliver power purchased under third party agreements (i.e., Non-Utility Generators). Existing Transmission Capacity for Native Load is listed in Attachment L of the ISO OATT.

Existing Transmission Agreement (“ETA”): An agreement between two or more Transmission Owners, or between a Transmission Owner and another entity, in existence at the time of ISO start-up and providing for transmission service by a Transmission Owner to another Transmission Owner or another entity. Table 1A of Attachment L lists all ETAs. ETAs include Transmission Wheeling Agreements (including MWAs and Third Party TWAs) and Transmission Facility Agreements.

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 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).

2.7 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: The transmission rights associated with: (1) Modified Wheeling Agreements; (2) Transmission Facility Agreements; and (3) Third Party Transmission Wheeling Agreements where the party entitled to exercise the transmission rights associated with such Agreements has chosen, as provided in the Tariff, to retain those rights rather than to convert those rights to Grandfathered TCCs.

Grandfathered TCCs: The TCCs associated with: (1) Modified Wheeling Agreements; (2) Transmission Facility Agreements with transmission wheeling provisions; and (3) Third Party TWAs where the party entitled to exercise the transmission rights associated with such Agreements has chosen, as provided by the Tariff, to convert those rights to TCCs.

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 5.14.1.2.11.

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 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 4.5.3.2 and Attachment J of this ISO Services Tariff to compensate a Supplier whose Import is Curtailed by the ISO.

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

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

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

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

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

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

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

Incremental TCC: A set of point-to-point Transmission Congestion Contract(s) that is awarded pursuant to Section 19.2.2 of Attachment M to 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 Transmission Owners transferred to the ISO Operational Control over designated transmission facilities.

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

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

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

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

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

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

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

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

Interface MW - Mile Methodology: The procedure used to allocate Original Residual TCCs determined prior to the first Centralized TCC Auction to Transmission Owners.

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 facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator. In New York, resources that depend upon wind, solar energy or landfill gas for their fuel have been classified as Intermittent Power Resources. Each Intermittent Power Resource that depends on wind as its fuel shall include all turbines metered at a single scheduling point identifier (PTID).

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

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

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

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

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

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

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

ISO 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, and the ISO/NYSRC Agreement.

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.

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.

Member Systems: The eight Transmission Owners that comprise the membership of the New York Power Pool.

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, or the minimum quantity of Demand Reduction a Demand Side Resource requires to provide Demand Reduction and the payment the Supplier requires to provide that level of Demand Reduction. If the Supplier is a BTM:NG Resource, 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, 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 Offer Floor: The price, in \$/MWh, determined by the ISO pursuant to Section 4.2.1.9 of the ISO Services Tariff and ISO Procedures, below which offers submitted by Demand Reduction Providers shall not be evaluated in the ISO's Security Constrained Unit Commitment.

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.

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: The total amount, in dollars, as calculated pursuant to Section Part 17.5.3.1 of Attachment B, remaining after collection of all charges and allocation of all payments associated with a round of a Centralized TCC Auction or a Reconfiguration Auction. Net Auction Revenue takes into account: (i) revenues from and payments for the award of TCCs in a Centralized TCC Auction or Reconfiguration Auction, (ii) payments to Transmission Owners releasing ETCNL, (iii) payments or charges to Primary Holders selling TCCs, (iv) payments to Transmission Owners releasing Original Residual TCCs, (v) O/R-t-S Auction Revenue Surplus Payments and U/D Auction Revenue Surplus Payments, and (vi) O/R-t-S Auction Revenue Shortfall Charges and U/D Auction Revenue Shortfall Charges. Net Auction Revenue may be positive or negative.

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 4.2.1.9 of the ISO Services Tariff and ISO Procedures to determine the Monthly Net Benefit Offer Floor, the threshold price at which the dispatch of demand response resources meets the test required by Commission Order No. 745.

Net Congestion Rent: The total amount, in dollars, as calculated pursuant to Section 17.5.2.1 of Attachment B, remaining after collection of all Congestion-related charges and allocation of all Congestion-related payments associated with the Day-Ahead Market. Net Congestion Rent takes into account: (i) charges and payments for Congestion Rents, (ii) settlements with TCC Primary Holders, (iii) O/R-t-S Congestion Rent Shortfall Charges and U/D Congestion Rent Shortfall Charges, and (iv) O/R-t-S Congestion Rent Surplus Payments and U/D Congestion Rent Surplus Payments. Net Congestion Rent may be positive or negative.

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 located within the NYCA or outside the NYCA, some of which may from time-to-time be subject to operational control by the ISO.

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

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

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

Non-Competitive Proxy Generator Bus: A Proxy Generator Bus for an area outside of the New York Control Area that has been identified by the ISO as characterized by non-competitive Import or Export prices, and that has been approved by the Commission for designation as a Non-Competitive Proxy Generator Bus. Non-Competitive Proxy Generator Buses are identified in Section 4.4.4 of the Services Tariff., as set forth in Section 4.4.2.2 of the MST

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

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

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

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

Normal Upper Operating Limit (UOL_N): The upper operating limit that a Generator, 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, or the maximum amount of demand that a Demand Side Resource expects to be able to reduce, 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.

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

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

NPCC: The Northeast Power Coordinating Council.

NRC: The Nuclear Regulatory Commission or any successor thereto.

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

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

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

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

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

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

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

Operating Reserves : Capacity that is available to supply Energy or reduce demand and that meets the requirements of the ISO. The ISO will administer Operating Reserves markets, in the manner described in this Article 4 and Rate Schedule 4 of this ISO Services Tariff, to satisfy the various Operating Reserves requirements, including locational requirements, established by the

Reliability Rules and other applicable reliability standards. The basic Operating Reserves products that will be procured by the ISO on behalf of the market are classified as follows:

- (1) Spinning Reserve: Operating Reserves provided by Generators and Demand Side Resources that meet the eligibility criteria set forth in Rate Schedule 4 of this ISO Services Tariff that 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. Spinning Reserves may not be provided by Demand Side Resources that are Local Generators or by Behind-the-Meter Net Generation Resources that are comprised of more than one generating unit that are dispatched as a single aggregate unit;
- (2) 10-Minute Non-Synchronized Reserve: Operating Reserves provided by Generators, Behind-the-Meter Net Generation Resources that are comprised of more than one generating unit that are dispatched as a single aggregate unit, or Demand Side Resources, including Demand Side Resources using Local Generators, that meet the eligibility criteria set forth in Rate Schedule 4 of this ISO Services Tariff and that can be started, synchronized and can change their output level within ten (10) minutes; and
- (3) 30-Minute Reserve: Synchronized Operating Reserves provided by Generators, except Behind-the-Meter Net Generation Resources that are comprised of more than one generating unit and dispatched as a single aggregate unit, and Demand Side Resources that are not Local Generators; or non-synchronized Operating Reserves provided by Generators, Behind-the-Meter Net Generation Resources that are comprised of more than one generating unit and dispatched as a single aggregate unit, or Demand Side Resources that meet the eligibility criteria set forth in Rate Schedule 4 of this ISO Services Tariff and that can respond to instructions to change their output level within thirty (30) minutes, including starting and synchronizing to the NYS Power System.

Operating Reserve Demand Curve: A series of quantity/price points that defines the maximum Shadow Price for Operating Reserves meeting a particular Operating Reserve requirement corresponding to each possible quantity of Resources that the ISO's software may schedule to meet that requirement. A single Operating Reserve Demand Curve will apply to both the Day-Ahead Market and the Real-Time Market for each of the ISO's twelve Operating Reserve requirements.

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.

Optimal Power Flow (“OPF”): The Power Flow analysis that is performed during the administration of the Centralized TCC Auction to determine the most efficient simultaneously feasible allocation of TCCs to Bidders (See Attachment M to 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: A TCC converted from Residual Transmission Capacity estimated prior to the first Centralized TCC Auction and allocated among the Transmission Owners utilizing the Interface MW-Mile Methodology prior to the first Centralized TCC Auction.

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.

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: A zone-to-zone TCC created when a Transmission Owner with a RCRR exercises its right to convert the RCRR into a TCC pursuant to Section 19.5.4 of Attachment M of 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; “RTC₀₀,” “RTC₁₅,” “RTC₃₀,” and “RTC₄₅” 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. RTC₁₅ 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 inject or withdraw in real-time by the ISO. Injections 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, or the HTP Scheduled Line.

Reconfiguration Auction: The monthly auction administered by the ISO in which Market Participants may purchase and sell one-month TCCs.

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 or Demand Reduction 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 or Demand Reduction 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 with the value of thirteen (13), used with the Regulation Movement Bids, to schedule Regulation Service providers in both the Day-Ahead and Real-Time Energy markets. The ISO calculates the Regulation Movement Multiplier 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 Generators 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 Generators 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.

Reserve Performance Index: An index created by the ISO for the purpose of calculating the Day Ahead Margin Assurance Payment pursuant to Attachment J of this Services Tariff made to Demand Side Resources scheduled to provide Operating Reserves in the Day-Ahead Market.

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”): A megawatt of transmission Capacity from one Load Zone to an electrically contiguous Load Zone, each of which is internal to the NYCA, that may be converted into an RCRR TCC by a Transmission Owner allocated the RCRR pursuant to Section 19.5 of Attachment M of the ISO OATT.

Residual Transmission Capacity: The transmission capacity determined by the ISO before, during and after the Centralized TCC Auction which is conceptually equal to the following:

$$\text{Residual Transmission Capacity} = \text{TTC} - \text{TRM} - \text{CBM} - \text{GTR} - \text{GTCC} - \text{ETCNL}$$

The TCCs associated with Residual Transmission Capacity cannot be accurately determined until the Centralized TCC Auction is conducted.

TTC is the Total Transfer Capability that can only be determined after the Residual Transmission Capacity is known.

GTR is the transmission capacity associated with Grandfathered Rights.

GTCC is the transmission capacity associated with Grandfathered TCCs.

ETCNL is the transmission capacity associated with Existing Transmission Capacity for Native Load.

TRM is the Transmission Reliability Margin.

CBM is the Capacity Benefit Margin.

Resource: An Energy Limited 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.

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.

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 Holders: Entities that: (1) purchase TCCs in the Secondary Market; (2) purchase TCCs in a Direct Sale from a Transmission Owner and have not been certified as a Primary Holder by the ISO; or (3) receive an allocation of Native Load TCCs from a Transmission Owner (See Attachment M). A Transmission Customer purchasing TCCs in a Direct Sale may qualify as a Primary Holder with respect to those TCCs purchased in that Direct Sale.

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: A market in which Primary and Secondary Holders sell TCCs by mechanisms other than through the Centralized TCC Auction or by Direct Sale. Buyers of TCCs in the Secondary Market shall neither pay nor receive Congestion Rents directly to or from the ISO.

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 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 follows Base Point Signals within a portion of its operating range, but self-commits.

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.

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. SCRs that do not use Local Generators may be offered as synchronized Operating Reserves and Regulation Service and Energy in the Day-Ahead Market. SCRs, using Local Generators rated 100 kW or higher, that are not visible to the ISO's Market Information System may also be offered as non-synchronized Operating Reserves.

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 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.

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 a Limited Energy Storage Resource; or (iii) provided during a Black Start restoration by Generators that provide Black Start Capability Service.

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 or a Demand Side Resource from a level of no Demand Reduction to its specified minimum level of Demand Reduction. If the Supplier is a BTM:NG Resource, 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.

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.

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 the least cost selection of additional Generators, which are to be committed, to meet: (i) 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) forecast Load and reserve requirements over the six-day period that follows the Dispatch Day.

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

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.

4.1 Market Services - General Rules

4.1.1 Overview

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

4.1.2 Independent System Operator Authority

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

Service under the ISO OATT.

4.1.3 Informational and Reporting Requirements

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

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, Regulation Service may be offered in tenths of a MW and provided further, pursuant to ISO Procedures, Special Case Resources may offer a minimum of 100 kW of Unforced Capacity in the Installed Capacity Market. Each Transaction above one (1) megawatt may be scheduled in tenths of a megawatt provided, however, Bilateral Transactions and External Transactions in the LBMP Market must be bid and scheduled in increments of one (1) megawatt.

4.1.5 Communication Requirements for Market Services

Customers and Transmission Customers shall utilize Internet service providers to access the ISO’s OASIS and bid/post system. Customers shall arrange for and maintain all communications facilities for the purpose of communication of commercial data to the ISO.

Each Customer shall be the customer of record for the telecommunications facilities and services it 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 or at an NYCA Interconnection with another Control Area must obtain Transmission Service under the ISO OATT. All Customers requesting service under the ISO Services Tariff to engage in Virtual Transactions must obtain Transmission Service under the ISO OATT.

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

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

A Supplier with a Generator or Demand Side Resource with a real time physical operating problem that makes it impossible for it to operate in the bidding mode in which it was scheduled shall notify the NYISO.

4.1.7 Customer Compliance with Laws, Regulations and Orders

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

4.1.7.1 Violations of FERC's orders, rules and regulations also violate this Section 4.1.7 of the ISO Services Tariff. In particular, if FERC or a court of competent jurisdiction determines there has been a violation of FERC's regulations related to electric energy market manipulation (see 18 C.F.R. Section

1c.2, or any successor provision thereto), such violation is also a violation of this ISO Services Tariff if such violation affects or is related to the ISO Administered Markets.

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

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

4.1.8 Commitment for Reliability

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

Re-dispatching costs incurred as a result of reductions in Transfer Capability caused by Storm Watch ("Storm Watch Costs") shall be aggregated and recovered on a monthly basis by the ISO exclusively from Transmission Customers in Load Zone J. The ISO shall calculate

Storm Watch Costs by multiplying the real-time Shadow Price of any binding constraint associated with a Storm Watch, by the higher of (a) zero; or (b) the scheduled Day-Ahead flow across the constraint minus the actual real-time flow across the constraint.

4.1.9 Cost Recovery for Units Responding to Local Reliability Rule I-R3 or I-R5

4.1.9.1 Eligibility for Cost Recovery

Generating units designated pursuant to the New York State Reliability Council's Local Reliability Rule I-R3 -- Loss of Generator Gas Supply (New York City) or I-R5 -- Loss of Generator Gas Supply (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 Local Reliability Rule I-R-3 or I-R5 is invoked pursuant to the provisions of this Section 4.1.9. For purposes of this Section 4.1.9, the periods of time in which the Eligible Unit burns the alternate fuel only because Local Reliability Rule I-R3 or I-R5 is invoked, including that period of time required to move into and out of Rule I-R3 or I-R5 compliance, shall be referred to as the "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 Rule I-R3 or I-R5 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 Local Reliability Rule I-R3 of I-R5 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 Rule I-R3 or I-R5.

4.1.9.3 Additional Cost Recovery

An Eligible Unit that seeks to recover costs incurred in connection with its compliance with Rule I-R3 or I-R5, 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 Rule I-R3 or I-R5. Such Implementation Agreements shall specify, among other terms and conditions, the facilities (or portions of facilities) used to meet obligations under Rule I-R3 or I-R5. 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 Rule I-R3 or I-R5 that vary with the amount of alternate fuel burned because I-R3 or I-R5 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 whether an alternate fuel is burned pursuant to I-R3 or I-R5 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.

4.2 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;
- e. Demand Reduction Bids; and
- f. For Behind-the-Meter Net Generation Resources, the forecasted Host Load for each hour of the Dispatch Day.

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

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

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

4.2.1.2 Load Forecasts

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

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

4.2.1.3.1 General Rules

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

If the Supplier using the ISO-Committed Flexible or Self-Committed Flexible bid mode is eligible to provide Regulation Service or Operating Reserves under Rate Schedules 3 and 4 respectively of this ISO Services Tariff, the Supplier's Bid may specify the quantity of Regulation Capacity it is making available and shall specify an emergency response rate that determines the quantity of Operating Reserves that it is capable of providing. Offers to provide Regulation Service and Operating Reserves must comply with the rules set forth in Rate

Schedules 3 and 4 of this ISO Services Tariff. If a Supplier that is eligible to provide Operating Reserves does not submit a Day-Ahead Availability Bid for Operating Reserves, its Day-Ahead Bid shall be rejected in its entirety. A Behind-the-Meter Net Generation Resource that is comprised of more than one generating unit that is dispatched as a single aggregate unit at a single PTID is not qualified to provide Regulation Service or Spinning Reserves. A Supplier may resubmit a complete Day-Ahead Bid, provided that the new Bid is timely. See Section 4.2.1.9 for bidding requirements for Demand Side Resources offering Energy in the Day-Ahead Market.

Suppliers other than Demand Side Resources entering a Bid into the Day-Ahead Market may also enter Day-Ahead Bids for each of the next nine (9) Dispatch Days. If not subsequently modified or withdrawn, these offers for subsequent Dispatch Days may be used by the ISO as offers from these Suppliers in the Day-Ahead Market for these subsequent Dispatch Days. For Suppliers that are providing Unforced Capacity in the ISO-administered ICAP Market for the month in which the Dispatch Day and the nine-day advance bidding period are encompassed, the ISO may enter the eighth day offer as the Bid for that Supplier's ninth day, if there is, otherwise no ninth-day Bid.

4.2.1.3.2 Bid Parameters

Day-Ahead Bids by Suppliers using the ISO-Committed Flexible, Self-Committed Flexible or ISO-Committed Fixed bid modes may identify-variable Energy price Bids, consisting of up to eleven monotonically increasing, constant cost incremental Energy steps, and other parameters described in ISO Procedures. Day-Ahead Bids from Demand Side Resources offering Operating Reserves or Regulation Service shall be ISO-Committed Flexible and shall have an Energy Bid price no lower than the Monthly Net Benefit Offer Floor. Day-Ahead offers

by Intermittent Power Resources that depend on wind 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 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.

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

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

4.2.1.4 Offers to Supply Energy from Self-Committed Fixed Generators

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

4.2.1.5 Bids to Supply Energy in Virtual Transactions

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

4.2.1.6 Bids to Purchase Energy in Virtual Transactions

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

4.2.1.7 Bilateral Transactions

Transmission Customers requesting Bilateral Transaction schedules shall identify hourly Transaction quantities (in MW) by Point of Injection and Point of Withdrawal, minimum run times associated with Firm Point-to-Point Transmission Service, if any, and shall provide other information (as described in ISO Procedures).

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

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

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

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

The ISO shall perform the Net Benefits Test and post on its web site the Monthly Net Benefit Offer Floor for each month by the 15th of the preceding month in accordance with ISO Procedures. The Net Benefits Test shall establish the threshold price below which the dispatch of Energy from Demand Side Resources is not cost-effective. The Net Benefits Test shall

consist of the following steps: (1) the ISO shall compile hourly supply curves for the Reference Month; (2) the ISO shall develop the average supply curve for the Study Month by updating the Reference Month supply curves for retirements and new entrants, and adjusting offers for changes in fuel prices; (3) the ISO shall apply an appropriate mathematical formula to smooth the average supply curve; and (4) the ISO shall evaluate the smoothed average supply curve to determine the Monthly Net Benefit Floor for the Study Month. The ISO shall apply the Monthly Net Benefit Offer Floor, as so calculated, to Bids submitted by Demand Response Providers for all hours in the Study Month.

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

4.2.2 ISO Responsibility to Establish a Statewide Load Forecast

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

4.2.3 Security Constrained Unit Commitment (“SCUC”)

Subject to ISO Procedures and Good Utility Practice, the ISO will develop a SCUC schedule over the Dispatch Day using a computer algorithm which simultaneously minimizes the total Bid Production Cost of: (i) supplying power or Demand Reductions to satisfy accepted purchasers’ Bids to buy Energy from the Day-Ahead Market; (ii) providing sufficient Ancillary

Services to support Energy purchased from the Day-Ahead Market consistent with the Regulation Service Demand curve and Operating Reserve Demand Curves set forth in Rate Schedules 3 and 4 respectively of this ISO Services Tariff; (iii) committing sufficient Capacity to meet the ISO's Load forecast and provide associated Ancillary Services; and (iv) meeting Bilateral Transaction schedules submitted Day-Ahead excluding schedules of Bilateral Transactions with Trading Hubs as their POWs. The computer algorithm shall consider whether accepting Demand Reduction Bids will reduce the total Bid Production Cost.

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

The schedule will include commitment of sufficient Generators and/or Demand Side Resources to provide for the safe and reliable operation of the NYS Power System. SCUC will treat a Behind-the-Meter Net Generation Resource as already being committed and available to be scheduled. Pursuant to ISO Procedures, the ISO may schedule any Resource to run above its UOL_N up to the level of its UOL_E . In cases in which the sum of all Bilateral Schedules, excluding Bilateral Schedules for Transactions with Trading Hubs as their POWs, and all Day-Ahead Market purchases to serve Load within the NYCA in the Day-Ahead schedule is less than the ISO's Day-Ahead forecast of Load, the ISO will commit Resources in addition to the Operating Reserves it normally maintains to enable it to respond to contingencies. The purpose of these additional resources is to ensure that sufficient Capacity is available to the ISO in real-time to enable it to meet its Load forecast (including associated Ancillary Services). In considering which additional Resources to schedule to meet the ISO's Load forecast, the ISO

will evaluate unscheduled Imports, and will not schedule those Transactions if its evaluation determines the cost of those Transactions would effectively exceed a Bid Price cap in the hours in which the Energy provided by those Transactions is required. In addition to all Reliability Rules, the ISO shall consider the following information when developing the SCUC schedule:

- (i) Load forecasts; (ii) Ancillary Service requirements as determined by the ISO given the Regulation Service Demand Curve and Operating Reserve Demand Curves referenced above;
- (iii) Bilateral Transaction schedules excluding Bilateral Schedules for Transactions with Trading Hubs as their POWs; (iv) price Bids and operating Constraints submitted for Generators or for Demand Side Resources; (v) price Bids for Ancillary Services; (vi) Decremental Bids and Sink Price Cap Bids for External Transactions; and (vii) Bids to purchase or sell Energy from or to the Day-Ahead Market. External Transactions with minimum run times greater than one hour will only be scheduled at the requested Bid for the full minimum run time. External Transactions with identical Bids and minimum run times greater than one hour will not be prorated. The SCUC schedule shall list the hourly injections and withdrawals for: (a) each Customer whose Bid the ISO accepts for the Dispatch Day; and (b) each Bilateral Transaction scheduled Day-Ahead excluding Bilateral Transactions with Trading Hubs as their POWs.

In the development of its SCUC schedule, the ISO may commit and de-commit Generators and Demand Side Resources, based upon any flexible Bids, including Minimum Generation Bids, Start-Up Bids, Curtailment Initiation Cost Bids, Energy, and Incremental Energy Bids and Decremental Bids received by the ISO provided however that: (a) the ISO shall commit zero megawatts of Energy for Demand Side Resources committed to provide Operating Reserves and Regulation Service; and (b) for Behind-the-Meter Net Generation Resources, the

ISO will consider for dispatch only those segments of the Resource's Incremental Energy Bids above the forecasted Host Load and subject to the Injection Limit.

The ISO will select the least cost mix of Ancillary Services and Energy from Suppliers, Demand Side Resources, and Customers submitting Virtual Transactions bids. The ISO may substitute higher quality Ancillary Services (*i.e.*, shorter response time) for lower quality Ancillary Services when doing so would result in an overall least bid cost solution. For example, 10-Minute Non-Synchronized Reserve may be substituted for 30-Minute Reserve if doing so would reduce the total bid cost of providing Energy and Ancillary Services.

4.2.3.1 Reliability Forecast for the Dispatch Day

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

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

A Transmission Owner may request commitment of additional Generators for a Dispatch Day following the close of the Day-Ahead Market to meet changed or local system conditions for the Dispatch Day that may cause the Day-Ahead schedules for the Dispatch Day to be

inadequate to ensure the reliability of its local system. The ISO will use SRE to fulfill a Transmission Owner's request for additional units.

All Generator commitments made in the Day-Ahead Market pursuant to this Section 4.2.3.1 shall be posted on the ISO website following the close of the Day-Ahead Market, in accordance with ISO procedures. In addition, the ISO shall post on its website a non-binding, advisory notification of a request, or any modifications thereto, made pursuant to this Section 4.2.3.1 in the Day-Ahead Market by a Transmission Owner to commit a Generator that is located within a Constrained Area, as defined in Attachment H of this Services Tariff. The advisory notification shall be provided upon receipt of the request and in accordance with ISO procedures.

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

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

4.2.4 Reliability Forecast for the Six Days Following the Dispatch Day

In the SCUC program, system operation shall be optimized based on Bids over the Dispatch Day. However, to preserve system reliability, the ISO must ensure that there will be sufficient resources available to meet forecasted Load and reserve requirements over the seven (7)-day period that begins with the next Dispatch Day. The ISO will perform a Supplemental Resource Evaluation (“SRE”) for days two (2) through seven (7) of the commitment cycle. If it is determined that a long start-up time Generator (*i.e.*, a Generator that cannot be scheduled by SCUC to start up in time for the next Dispatch Day) is needed for reliability, the ISO shall accept a Bid from the Generator and the Generator will begin its start-up sequence. During each day of the start-up sequence, the ISO will perform an SRE to determine if long start-up time Generators will still be needed as previously forecasted. If at any time it is determined that the Generator will not be needed as previously forecasted, the ISO shall order the Generator to abort its start-up sequence.

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

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

The ISO shall perform the SRE as follows: (1) The ISO shall develop a forecast of daily system peak Load for days two (2) through seven (7) in this seven (7)-day period and add the appropriate reserve margin; (2) the ISO shall then forecast its available Generators for the day in

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

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

4.2.5 Post the Day-Ahead Schedule

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

4.2.6 Day-Ahead LBMP Market Settlements

The ISO shall calculate the Day-Ahead LBMPs for each Load Zone and at each Generator bus and Demand Reduction Bus as described in Attachment B. Each Supplier that bids a Generator into the ISO Day-Ahead Market and is scheduled in the SCUC to sell Energy in the Day-Ahead Market will be paid the product of: (a) the Day-Ahead hourly LBMP at the applicable Generator bus; and (b) the hourly Energy schedule. Each Supplier that bids an External Transaction into the Day-Ahead LBMP Market and is scheduled in the SCUC to sell Energy into the Day-Ahead LBMP Market will be paid the product of (a) the Day-Ahead LBMP at the applicable Proxy Generator Bus and (b) the External Transaction schedule. For each

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

Load Zone associated with that Trading Hub; and (b) the Bilateral Transaction scheduled MW.

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

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

4.4 Real-Time Markets and Schedules

4.4.1 Real-Time Commitment (“RTC”)

4.4.1.1 Overview

RTC will make binding unit commitment and de-commitment decisions for the periods beginning fifteen minutes (in the case of Resources that can respond in ten minutes) and thirty minutes (in the case of Resources that can respond in thirty minutes) after the scheduled posting time of each RTC run, will provide advisory commitment information for the remainder of the two and a half hour optimization period, and will produce binding schedules for External Transactions to begin at the start of each quarter hour. RTC will treat a Behind-the-Meter Net Generation Resource 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.

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

Intermittent Power Resources that depend on wind 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 Energy, Operating Reserves and/or Regulation Service. Customers that submit such Bids may specify different Bid parameters in real-time than they did Day-Ahead. Incremental Energy Bids 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 submitted in the Day-Ahead Market or the mitigated Day-Ahead Incremental Energy Bids where appropriate, for portions of the Capacity of such Resources that were scheduled in the Day-Ahead Market, if not otherwise prohibited pursuant to other provisions of the tariff. Minimum Generation Bids, Start-Up Bids, Regulation Service Bids for any hour in which such Resources received a Day-Ahead Energy schedule or a Regulation Service schedule, as appropriate, may not exceed the Minimum Generation Bids, Start-up Bids, or Regulation Service Bids, as appropriate, submitted for those Resources in the Day-Ahead Market. Additionally, Real-Time Minimum Run Qualified Gas Turbine Customers shall not increase their previously submitted Real-Time Incremental Energy Bids, Minimum Generation Bids, or Start-Up Bids within 135 minutes of the dispatch hour. Bids to supply Energy or Ancillary Services shall be subject to the rules set forth in Section 4.2.1 of this ISO Services Tariff. For Behind-the-Meter Net Generation Resources, the ISO will consider only

those segments of the Resource's Incremental Energy Bids above the forecasted Host Load and subject to the Injection Limit.

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

A Generator with a real time physical operating problem that makes it impossible for it to operate in the bidding mode in which it was scheduled Day-Ahead should notify the NYISO. 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 NYISO.

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

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

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

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

The ISO may vary External Transaction Schedules at Proxy Generator Buses that are authorized to schedule transactions on an intra-hour basis if the party submitting the Bid for such a Transaction elects to permit variable scheduling. The ISO may also vary External Transaction Schedules at CTS Enabled Proxy Generator Buses. External Transaction Bids submitted to import Energy from, or export Energy to Proxy Generator Buses that are authorized to schedule

transactions on either an intra-hour or hourly basis shall indicate whether the ISO may vary schedules associated with those Bids within each hour. Transmission Customers scheduling External Bilateral Transactions shall also be subject to the provisions of Section 16, Attachment J of the ISO OATT.

4.4.1.2.3 Self-Commitment Requests

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

4.4.1.2.4 ISO-Committed Fixed

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

RTC shall schedule ISO-Committed Fixed Generators.

4.4.1.3 External Transaction Scheduling

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

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

Except as specifically noted in Section 4.4.2, 4.4.3 and 4.4.4 of this ISO Services Tariff, RTC will make all Resource commitment and de-commitment decisions. RTC will make all economic commitment/de-commitment decisions based upon available offers assuming Suppliers internal to the NYCA have a one-hour minimum run time; provided however, Real-Time Minimum Run Qualified Gas Turbines shall be assumed to have a two-hour minimum run time. For Behind-the-Meter Net Generation Resources, RTC will consider only those segments of the Resource's Incremental Energy Bids above the forecasted Host Load and subject to the Injection Limit.

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

RTC₁₅ will begin at the start of the first hour of the RTC co-optimization period and will post its commitment, de-commitment, and External Transaction scheduling decisions no later than fifteen minutes after the start of that hour. During the RTC₁₅ run, RTC will:

- (i) Commit Resources with 10-minute start-up times that should be synchronized by the time that the results of the next RTC run are posted so that they will be synchronized and running at their scheduled generation 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 generation levels by that time;
- (iii) De-commit Resources that should be disconnected from the network by the time that the results of the next RTC run are posted so that they will be disconnected by that time;
- (iv) Issue advisory commitment and de-commitment guidance for periods more than thirty minutes in the future and advisory dispatch information;
- (v) Schedule economic hourly External Transactions for the next hour;
- (vi) Schedule economic 15 minute External Transactions, for the quarter hour for which the results of the next RTC run are posted, at Variably Scheduled Proxy Generator Buses other than a CTS Enabled Proxy Generator Bus;

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

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

- (i) Commit Resources with 10-minute start-up times that should be synchronized by the time that the results of the next RTC run are posted so that they will be synchronized and running at that time;
- (ii) Commit Resources with 30-minute start-up times that should be synchronized by the time that the results of the RTC run following the next RTC run are posted so that they will be synchronized and running at that time;
- (iii) De-commit Resources that should be disconnected from the network by the time that the results of the next RTC run are posted so that they will be disconnected at that time;
- (iv) Issue advisory commitment, de-commitment, and dispatching guidance for the period from thirty minutes in the future until the end of the RTC co-optimization period;
- (v) Either reaffirm that the External Transactions scheduled by previous RTC runs should continue to flow in the next hour, or inform the ISO that External Transactions may need to be reduced;

- (vi) Schedule economic 15 minute External Transactions, for the quarter hour for which the results of the next RTC run are posted, at Variably Scheduled Proxy Generator Buses other than a CTS Enabled Proxy Generator Bus;
- (vii) Schedule economic 15 minute External Transactions, for the quarter hour for which the results of the next RTC run are posted, at a CTS Enabled Proxy Generator Bus; and
- (viii) Schedule ISO-Committed Fixed Resources.

4.4.1.5 External Transaction Settlements

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

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

4.4.2 Real-Time Dispatch

4.4.2.1 Overview

The Real-Time Dispatch will make dispatching decisions, send Base Point Signals to Internal Generators and Demand Side Resources, produce schedules for intra-hour External Transactions at Dynamically Scheduled Proxy Generator Buses, calculate Real-Time Market clearing prices for Energy, Operating Reserves, and Real-Time Market Prices for Regulation Service, and establish real-time schedules for those products on a five-minute basis, starting at the beginning of each hour. The Real-Time Dispatch will not make commitment decisions and will not consider start-up costs in any of its dispatching or pricing decisions, except as specifically provided in Section 4.4.2.3 below. Each Real-Time Dispatch run will co-optimize to

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

4.4.2.2 External Transaction Scheduling

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

4.4.2.3 Calculating Real-Time Market LBMPs and Advisory Prices

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

4.4.2.4 Real-Time Pricing Rules for Scheduling Ten Minute Resources

RTD may commit and dispatch, for pricing purposes, Resources meeting Minimum Generation Levels and capable of starting within ten minutes (“eligible Resources”) when

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

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

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

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

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

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

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

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

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

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

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

4.4.2.7 Post the Real-Time Schedule

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

4.4.3 Real-Time Dispatch - Corrective Action Mode

When the ISO needs to respond to system conditions that were not anticipated by RTC or the regular Real-Time Dispatch, *e.g.*, the unexpected loss of a major Generator or Transmission line, it will activate the specialized RTD-CAM program. RTD-CAM runs will be nominally

either five or ten minutes long, as is described below. Unlike the Real-Time Dispatch, RTD-CAM will have the ability to commit certain Resources, and schedule intra-hour External Transactions at Dynamically Scheduled Proxy Generator Buses. When RTD-CAM is activated, the ISO will have discretion to implement various measures to restore normal operating conditions. These RTD-CAM measures are described below.

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

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

4.4.3.1 RTD-CAM Modes

4.4.3.1.1 Reserve Pickup

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

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 have this discretion in large events. The distinction also has significance with respect to a Supplier’s eligibility to receive Bid Production Cost guarantee payment in accordance with Section 4.6.6 and Attachment C of this ISO Services Tariff.

4.4.3.1.2 Maximum Generation Pickup

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

4.4.3.1.3 Base Points ASAP -- No Commitments

The ISO will enter this RTD-CAM mode when changed circumstances make it necessary to issue an updated set of Base Point Signals. Examples of changed circumstances that could necessitate taking this step include correcting line, contingency, or transfer overloads and/or voltage problems caused by unexpected system events. When operating in this mode, RTD-CAM will produce schedules and Base Point Signals for the next five minutes but will only

redispatch Generators that are capable of responding within five minutes. RTD-CAM will not commit or de-commit Resources in this mode.

4.4.3.1.4 Base Points ASAP -- Commit As Needed

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

4.4.3.1.5 Re-Sequencing Mode

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

4.4.3.2 Calculating Real-Time LBMPs

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

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

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

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

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

Notes:

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

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

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

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

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 and injections 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 injections 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, 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 topping or extraction turbine Generators utilized in replacing or repowering existing steam supplies from such units (in accordance with good engineering and economic design) that cannot follow schedules, up to a maximum total of 523 MW of such units.

This procedure shall not apply to Behind-the-Meter Net Generation Resources 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, 4.5.4, 4.5.5 and 4.5.6 of this Tariff, references to “scheduled” Energy injections and withdrawals shall encompass injections and withdrawals that are scheduled Day-Ahead, as well as injections and withdrawals that occur in connection with real-time Bilateral Transactions. In Sections 4.5.1, 4.5.3, 4.5.4 and 4.5.6 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, 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 When Actual Energy Withdrawals Exceed Scheduled Energy Withdrawals Other Than Scheduled or Actual Withdrawals in Virtual Transactions

When the Actual Energy Withdrawals by a Customer over an RTD interval exceed the Energy withdrawals scheduled over that RTD interval, the ISO shall charge the Real-Time LBMP for Energy equal to the product of: (a) the Real-Time LBMP calculated in that RTD interval for each applicable Load Zone; and (b) the difference between the Actual Energy Withdrawals and the scheduled Energy withdrawals at that Load Zone.

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.

4.5.2 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.

4.5.3 Settlement When Actual Energy Injections are Less Than Scheduled Energy Injections or Actual Demand Reductions are Less Than Scheduled Demand Reductions

4.5.3.1 General Rule

When the Actual Energy Injections by a Supplier over an RTD interval are less than the Energy injections scheduled Day-Ahead over that RTD interval, the Supplier shall pay a charge

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

4.5.3.2 Failed Transactions

If an Energy injection scheduled by RTC at a Proxy Generator Bus fails in the ISO's checkout process, the Supplier or Transmission Customer that was scheduled to make the injection will pay the Energy imbalance charge described above in Section 4.5.3.1. In addition, if 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's Market Mitigation and Analysis Department will determine whether the Transaction associated with an injection failed for reasons within a Supplier's or Transmission Customer's control.

If an Energy injection at a Proxy Generator Bus is determined to have failed for reasons within a Supplier's or Transmission Customer's control, the Financial Impact Charge will equal: (i) the difference computed by subtracting the actual real-time Energy injection from the amount of the Import scheduled by RTC; multiplied by (ii) the greater of the 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 4.5.4.2.

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.

4.5.3.3 Capacity Limited Resources and Energy Limited Resources

For any hour in which: (i) a Capacity Limited Resource 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 requests a reduction for Capacity limitation reasons; and (iv) the ISO reduces the Capacity Limited Resource's upper operating limit to a level equal to, or greater than, its bid-in upper operating limit; the imbalance charge for Energy, Operating Reserve Service or Regulation Service imposed on that Capacity Limited Resource for that hour for its 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 Day-Ahead schedule for each of these services minus the

amount of these services that it has an obligation to supply pursuant to its ISO-approved schedule. When a Capacity Limited Resource's 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 4.5.3.1.

For any day in which: (i) an Energy Limited Resource 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 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.

4.5.3.4 Demand Reductions

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

When the verified actual Demand Reduction over an hour from a Demand Reduction Provider that is not the LSE providing Energy service to the Demand Side Resource(s) that produced the reduction is less than the Demand Reduction scheduled over that hour, then (1) the LSE providing Energy service to the Demand Reduction Provider's Demand Side Resource(s)

shall pay a Demand Reduction imbalance charge equal to the product of (a) the Day-Ahead LBMP calculated for that hour for the applicable Load bus and (b) the difference between the scheduled Demand Reduction and the verified actual Demand Reduction at that bus in that hour, and (2) the Demand Reduction Provider will pay an amount equal to (a) the product of (i) the higher of the Day-Ahead LBMP or the Real-Time LBMP calculated for that hour for the applicable Load bus, and (ii) the difference between the scheduled Demand Reduction and the verified actual Demand Reduction at that bus in that hour, and (b) minus the amount paid by the LSE providing service to the Demand Reduction Provider's Demand Side Resource(s) under (1), above.

4.5.4 Settlement When Actual Energy Withdrawals are Less Than Scheduled Energy Withdrawals Other Than Actual or Scheduled Withdrawals in Virtual Transactions

4.5.4.1 General Rules

When a Customer's Actual Energy Withdrawals over an RTD interval are less than its Energy withdrawals scheduled Day-Ahead over that RTD interval, the Customer shall be paid the product of: (a) the Real-Time LBMP calculated in that RTD interval for each applicable Load Zone; and (b) the difference between the scheduled Energy withdrawals and the Actual Energy Withdrawals in that Load Zone. In addition, a Customer LSE providing Energy service to a Demand Reduction Provider's Demand Side Resource in a Load Zone shall be charged the product of: (a) the Real-Time hourly LBMP for that Load Zone; and (b) the actual Demand Reduction at the Demand Reduction Bus in that Load Zone.

4.5.4.2 Failed Transactions

If an Energy withdrawal at a Proxy Generator Bus scheduled by RTC fails in the ISO's checkout process, the Supplier or Transmission Customer that was scheduled to make the

withdrawal will pay or be paid the energy imbalance charge described above in Section 4.5.4.1.

In addition, if the checkout failure occurred for the reasons within the Supplier's or Transmission Customer's control it will be required to pay the "Financial Impact Charge" described below.

The ISO's Market Mitigation and Analysis Department will determine whether the Transaction associated with a withdrawal failed for reasons within a Supplier's or Transmission Customer's control.

If an Energy withdrawal at a Proxy Generator Bus is determined to have failed for reasons within a Supplier's or Transmission Customer's control, the Financial Impact Charge will equal: (i) the difference computed by subtracting the actual real-time Energy withdrawal from the amount of the Export scheduled by RTC; multiplied by (ii) the 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 4.5.3.2.

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.

4.5.5 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:

(1) the Real-Time LBMP calculated in that hour for the applicable Load Zone; and (b) the scheduled Day-Ahead Energy Withdrawal of the Customer for that Hour in that Load Zone.

4.5.6 Settlement When Actual Energy Injections Exceed Scheduled Energy Injections

When Actual Energy Injections from a Generator over an RTD interval exceed the Energy injections scheduled Day-Ahead over the RTD interval the Supplier shall be paid the product of: (1) the Real-Time LBMP calculated in that RTD interval for the applicable Generator bus and (2) the difference between the lesser of (i) the Supplier's Actual Energy Injection or (ii) its Real-Time Scheduled Energy Injection for that RTD interval, plus any Compensable Overgeneration and the Supplier's Day-Ahead scheduled Energy injection over the RTD interval, unless the payment that the Supplier would receive for such injections would be negative (i.e., unless the LBMP calculated in that RTD interval at the applicable Generator's bus is negative) in which case the Supplier shall be paid the product of: (1) the Real-Time LBMP calculated in that RTD interval for the applicable Generator bus and (2) the difference between the Supplier's Actual Energy Injection for that RTD interval and the Supplier's Day-Ahead scheduled Energy injection over that RTD interval. A Generator 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's actual output, or to address reliability concerns. Suppliers shall not be compensated for Energy in excess of their Real-Time Scheduled Energy Injections, except: (i) for Compensable Overgeneration; (ii) when the ISO initiates a large event reserve pickup or a maximum generation pickup under RTD-CAM; or (iii) when a Transmission Owner initiates a reserve pickup in accordance with a Reliability Rule, including a Local Reliability Rule. When there is no large event reserve pickup or maximum generation pickup, or when there is such an instruction but a Supplier is not located in the area affected by the maximum generation pickup, that Supplier shall not be compensated

for Energy in excess of its Real-Time Scheduled Energy Injection plus any Compensable Overgeneration. When there is a reserve pickup, or when there is a maximum generation pickup and a Supplier is located in the area affected by it, and the Supplier was either scheduled to operate in RTD or subsequently was directed to operate by the ISO, that Supplier shall be paid based on the product of: (1) the Real-Time LBMP calculated in that RTD Interval for the applicable Generator bus; and (2) the Actual Energy Injection minus the Energy injection scheduled Day-Ahead.

4.5.7 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.

4.5.8 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.

4.5.9 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.

5.11 Requirements Applicable to LSEs

5.11.1 Allocation of the NYCA Minimum Unforced Capacity Requirement

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 hour in which actual Load in the NYCA was highest (the “NYCA peak Load”) 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 at the time of the NYCA peak Load 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 Transmission District or municipal electric utility Load forecast coincident with the NYCA peak shall be the product of that Transmission District or municipal electric utility’s Adjusted Actual Load at the time of the NYCA peak Load multiplied by 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. Each Transmission Owner must also submit aggregate Adjusted Load data, coincident with the NYCA peak hour, for all customers served by each LSE active within its Transmission District. The aggregate Load data may be derived from direct meters or Load profiles of the customers served. Each Transmission Owner shall be required to submit such forecasts and aggregate peak Load data in accordance with the ISO Procedures. 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. 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 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.

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 for that LSE's customers in each Transmission District to the NYCA peak Load forecast.

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

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. 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 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, 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. 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. 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.

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. The Locational Minimum Unforced Capacity Requirement for each Locality shall equal the product of the Locational Minimum Installed Capacity Requirement for a given Locality (with or without the UDRs if there is a capability year adjustment election by a rights holder) 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 DMNCs 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. 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.

Qualified Resources 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.

In addition, any Customer that purchases Unforced Capacity associated with any generation that is subject to capacity market mitigation measures in an ISO-administered auction may not resell that Unforced Capacity in a subsequent auction at a price greater than the annual mitigated price cap, as applied in accordance with the ISO Procedures in accordance with Sections 5.13.2, 5.13.3, and 5.14.1 of this Tariff. The ISO shall inform Customers that purchase Unforced Capacity in an ISO-administered auction of the amount of Unforced Capacity they have purchased that is subject to capacity market mitigation measures.

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.

5.12 Requirements Applicable to Installed Capacity Suppliers

5.12.1 Installed Capacity Supplier Qualification Requirements

In order to qualify as an Installed Capacity Supplier, Generators and controllable transmission projects electrically located in the NYCA must have obtained Capacity Resource Interconnection Service (“CRIS”) pursuant to the applicable provisions of Attachment S to the ISO OATT, and controllable transmission projects must also have obtained Unforced Capacity Deliverability Rights. Even if a Generator has otherwise satisfied the requirements to participate in the ISO’s Installed Capacity market, a Generator in Inactive Reserves, an ICAP Ineligible Forced Outage, a Mothball Outage, or that is Retired is ineligible to participate in the ISO’s Installed Capacity market. A Generator that elects to participate in the ICAP Market, and is within a defined electrical boundary, electrically interconnected with, and routinely serves a Host Load (which Host Load does not consist solely of Station Power) at a single PTID can only participate in the Installed Capacity market as a Behind-the-Meter Net Generation Resource.

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 last paragraph of Section 5.12.1 below, Responsible Interface Parties, existing municipally-owned generation, Energy Limited Resources, and Intermittent Power Resources, to the extent those entities are subject to the requirements of Section 5.12.11 of this Tariff, shall:

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

- 5.12.1.2 in accordance with the ISO Procedures, perform DMNC or DMGC tests and submit the results to the ISO, or provide to the ISO appropriate historical production data;
- 5.12.1.3 abide by the ISO Generator maintenance coordination procedures;
- 5.12.1.4 provide the expected return date from any outages (including partial outages) to the ISO;
- 5.12.1.5 in accordance with the ISO Procedures,
 - 5.12.1.5.1 provide documentation demonstrating that it will not use the same Unforced Capacity for more than one (1) buyer at the same time, and
 - 5.12.1.5.2 in the event that the Installed Capacity Supplier supplies more Unforced Capacity than it is qualified to supply in any specific month (*i.e.*, is short on Capacity), documentation that it has procured sufficient Unforced Capacity to cover this shortfall.
- 5.12.1.6 except for Installed Capacity Marketers and Intermittent Power Resources that depend upon wind or solar as their fuel, Bid into the Day-Ahead Market, unless the Energy Limited Resource, Generator, Limited Control Run-of-River Hydro Resource or System Resource is unable to do so due to an outage as defined in the ISO Procedures or due to temperature related de-ratings. Generators may also enter into the MIS an upper operating limit that would define the operating limit under normal system conditions. The circumstances under which the ISO will direct a Generator to exceed its upper operating limit are described in the ISO Procedures;
- 5.12.1.7 provide Operating Data in accordance with Section 5.12.5 of this Tariff;

- 5.12.1.8 provide notice to the ISO, prior to the commencement of the Annual Transmission Reliability Assessment on March 1, of any transfers of deliverability rights to be carried out pursuant to Sections 25.9.4 - 25.9.6 of Attachment S to the ISO OATT;
- 5.12.1.9 comply with the ISO Procedures;
- 5.12.1.10 when the ISO issues a Supplemental Resource Evaluation request (an SRE), Bid into the in-day market 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; and
- 5.12.1.11 Installed Capacity Suppliers located East of Central-East shall Bid in the Day-Ahead and Real-Time Markets all Capacity available for supplying 10-Minute Non-Synchronized Reserve (unless the Generator is unable to meet its commitment because of an outage as defined in the ISO Procedures), except for the Generators described in Subsections 5.12.1.11.1, 5.12.1.11.2 and 5.12.1.11.3 below:
- 5.12.1.11.1 Generators providing Energy under contracts executed and effective on or before November 18, 1999 (including PURPA contracts) in which the power purchasers do not control the operation of the supply source but would be responsible for penalties for being off-schedule, with the exception of Generators under must-take PURPA contracts executed and effective on or before November 18, 1999, who have not provided telemetering to their local TO and

historically have not been eligible to participate in the NYPP market, which will continue to be treated as TO Load modifiers under the ISO-administered markets;

5.12.1.11.2 Existing topping turbine Generators and extraction turbine Generators producing Energy resulting from the supply of steam to the district steam system located in New York City (LBMP Zone J) in operation on or before November 18, 1999 and/or topping or extraction turbine 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 523 MW of such units; and

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

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

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

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

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

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

the applicable category specified in the definition of “Affiliated Entity” in Section 23.2.1 of Attachment H of the Services Tariff.

5.12.2 Additional Provisions Applicable to External Installed Capacity Suppliers

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

5.12.2.1 Provisions Addressing the Applicable External Control Area

External Generators, External System Resources, and Control Area System Resources qualify as Installed Capacity Suppliers if they demonstrate to the satisfaction of the NYISO that the Installed Capacity Equivalent of their Unforced Capacity is deliverable to the NYCA or, 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, or, in the case of Control Area System Resources, if they demonstrate that the External Control Area will afford the NYCA Load the same curtailment priority that they afford their own Control Area Native Load Customers. The amount of Unforced Capacity that may be supplied by such entities qualifying pursuant to the alternative criteria may be reduced by the ISO, pursuant to ISO Procedures, to reflect the possibility of curtailment. External Installed Capacity associated with Import Rights or UDRs is subject to the same deliverability requirements applied to Internal Installed Capacity Suppliers associated with UDRs.

5.12.2.2 Additional Provisions Addressing Internal Deliverability and Import Rights

In addition to the provisions contained in Section 5.12.2.1 above, External Installed Capacity not associated with UDRs or External CRIS Rights will be subject to the deliverability

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

The import limit set for External Installed Capacity not associated with UDRs 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 and External CRIS Rights forecast for the upcoming Capability Year, and (iii) would not degrade the transfer capability of any Other Interface by more than the threshold identified in Section 25.7.9 of Attachment S to the ISO OATT. Import limits set for External Installed Capacity will reflect the modeling of

awarded External CRIS rights, but the awarded External CRIS rights will not be adjusted as part of import limit-setting process. Procedures for qualifying selling, and delivery of External Installed Capacity are detailed in the Installed Capacity Manual.

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

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

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

survive for the term of the relevant External Installed Capacity contract or until the relevant External Generator is retired.

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

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

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

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

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

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

$$\begin{aligned} & \text{Rights allocated to entity } i \\ &= 1090 \\ & \quad * (MW_i * \text{contract/commitment length}_i) \\ & \quad / \sum_j (MW_j * \text{contract/commitment length}_j) \end{aligned}$$

$j = 1, \dots, \#$ entities requesting import rights

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

5.12.2.3.5 Any portion of the previously grandfathered 1090 MW not converted through this process will no longer be grandfathered from deliverability.

Previously grandfathered rights converted to External CRIS Rights but then terminated will no longer be grandfathered from deliverability.

5.12.2.4 Offer Cap Applicable to Certain External CRIS Rights

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

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

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

5.12.3 Installed Capacity Supplier Outage Scheduling Requirements

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

rescheduling of outages. In the case of Generators 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.

A Generator 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.

A Generator 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 Supplier 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 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.

- (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.

5.12.5 Operating Data Reporting Requirements

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

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

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

To qualify as Installed Capacity Suppliers in the NYCA, Generators, External Generators, System Resources, External System Resources, Energy Limited Resources, Responsible Interface Parties, Intermittent Power Resources, Limited Control Run-of-River Hydro Resources, and municipally owned generation or the purchasers of Unforced Capacity associated with those Resources shall submit GADS Data, data equivalent to GADS Data, or other Operating Data to the ISO in accordance with the ISO Procedures. Prior to the successful

implementation of a software modification that allows gas turbines to submit multiple bid points, these units shall not be considered to be forced out for any hours that the unit was available at its base load capability in accordance with the ISO Procedures. This section shall also apply to any Installed Capacity Supplier, External or Internal, using UDRs to meet Locational Minimum Installed Capacity Requirements.

5.12.5.2 Control Area System Resources

To qualify as Installed Capacity Suppliers in the NYCA, Control Area System Resources, or the purchasers of Unforced Capacity associated with those Resources, shall submit CARL Data and actual system failure occurrences data to the ISO each month in accordance with the ISO Procedures.

5.12.5.3 Transmission Projects Granted Unforced Capacity Deliverability Rights

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

5.12.6 Capacity Calculations, Operating Data Default, Value and Collection

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

The ISO shall calculate the amount of Net-ICAP for each Behind-the-Meter Net Generation Resource as the Adjusted DMGC of the Generator of the Behind-the-Meter Net Generation Resource minus the Resource's Adjusted Host Load in accordance with this Tariff and ISO Procedures.

5.12.6.1.1 Adjusted DMGC

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

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

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

5.12.6.1.2 Adjusted Host Load

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

The Adjusted Host Load shall be calculated by the ISO on an annual basis prior to the start of the Summer Capability Period and in accordance with ISO Procedures, based upon the

Behind-the-Meter Net Generation Resource's Average Coincident Host Load for the prior Summer Capability Period and the Winter Capability Period before that.

5.12.6.1.2.1 Average Coincident Host Load

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

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

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

5.12.6.1.2.2 Determination of Adjusted Host Load

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

5.12.6.2 UCAP Calculations

The ISO shall calculate for each Resource the amount of Unforced Capacity that each Installed Capacity Supplier is qualified to supply in the NYCA in accordance with formulae provided in the ISO Procedures.

The amount of Unforced Capacity that each Generator, except for the Generator of a Behind-the-Meter Net Generation Resource, System Resource, Energy Limited Resource, Special Case Resource, and municipally-owned generation is authorized to supply in the NYCA shall be based on the ISO's calculations of individual Equivalent Demand Forced Outage Rates. The amount of Unforced Capacity that each Control Area System Resource is authorized to supply in the NYCA shall be based on the ISO's calculation of each Control Area System Resource's availability. The amount of Unforced Capacity that each Intermittent Power Resource is authorized to supply in the NYCA shall be based on the NYISO's calculation of the amount of capacity that the Intermittent Power Resource can reliably provide during system peak Load hours in accordance with ISO Procedures. Except as provided in Section 5.12.6.2.1 of this Services Tariff, this calculation shall not include hours in any month that the Intermittent Power Resource was in an outage state that started on or after May 1, 2015 and that precluded its eligibility to participate in the Installed Capacity market. The amount of Unforced Capacity that

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

The ISO shall calculate separate Summer and Winter Capability Period Unforced Capacity values for each Generator, System Resource, Special Case Resource, Energy Limited Resource, and municipally owned generation and update them periodically using a twelve-month calculation 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 prior 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 Intermittent Power Resources and update them seasonally as described in ISO Procedures.

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

5.12.6.2.1 Exceptions

A Generator 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 Generator'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 Generator 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 Generator's Unforced Capacity upon

its return to service, the NERC class average derating factor in lieu of a derating factor developed from unit-specific data even if the modifications to allow use of a new primary fuel are not material and do not require the submission of a new Interconnection Request.

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

5.12.6.3 Default Unforced Capacity

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

5.12.7 Availability Requirements

Subsequent to qualifying, each Installed Capacity Supplier shall, except as noted in Section 5.12.11 of this Tariff, on a daily basis: (i) schedule a Bilateral Transaction; (ii) Bid Energy in each hour of the Day-Ahead Market in accordance with the applicable provisions of Section 5.12.1 of this Tariff; or (iii) notify the ISO of any outages. An RMR Generator can only schedule a Bilateral Transaction to the extent expressly authorized in its RMR Agreement. The total amount of Energy that an Installed Capacity Supplier schedules, bids, or declares to be unavailable on a given day must equal or exceed the Installed Capacity Equivalent of the Unforced Capacity it supplies.

5.12.8 Unforced Capacity Sales

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

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

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

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

New Generators and Generators that have increased their Capacity since the previous Summer Capability Period due to changes in their generating equipment may, after satisfying the deliverability requirements set forth in the applicable provisions of Attachment X, Attachment Z and Attachment S to the ISO OATT, qualify to supply Unforced Capacity on a foregoing basis during the Summer Capability Period based upon a DMNC test, or the DMGC test of a Generator of a Behind-the-Meter Net Generation Resource, that is performed and reported to the ISO after March 1 and prior to the beginning of the Summer Capability Period DMNC Test Period. The Generator will be required to verify the claimed DMNC or DMGC rating by performing an additional test during the Summer DMNC Test Period. Any shortfall between the amount of Unforced Capacity supplied by the Generator for the Summer Capability Period and the amount verified during the Summer DMNC Test Period will be subject to deficiency charges

pursuant to Section 5.14.2 of this Tariff. The deficiency charges will be applied to no more than the difference between the Generator's previous Summer Capability Period Unforced Capacity and the amount of Unforced Capacity equivalent the Generator supplied for the Summer Capability Period.

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

Any Installed Capacity Supplier, except as noted in Section 5.12.11 of this ISO Services Tariff, which fails on a daily basis to schedule, Bid, or declare to be unavailable in the Day-Ahead Market an amount of Unforced Capacity, expressed in terms of Installed Capacity Equivalent, that it certified for that day, rounded down to the nearest whole MW, is subject to

sanctions pursuant to Section 5.12.12.2 of this Tariff. If an entity other than the owner of an Energy Limited Resource, Generator, System Resource, Behind-the-Meter Net Generation Resource, or Control Area System Resource that is providing Unforced Capacity is responsible for fulfilling bidding, scheduling, and notification requirements, the owner and that entity must designate to the ISO which of them will be responsible for complying with the scheduling, bidding, and notification requirements. The designated bidding and scheduling entity shall be subject to sanctions pursuant to Section 5.12.12.2 of this ISO Services Tariff.

5.12.9 Sales of Unforced Capacity by System Resources

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

5.12.10 Curtailment of External Transactions In-Hour

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

5.12.11 Responsible Interface Parties, Municipally-Owned Generation, Energy Limited Resources and Intermittent Power Resources

5.12.11.1 Responsible Interface Parties

Responsible Interface Parties may qualify as Installed Capacity Suppliers, without having to comply with the daily bidding, scheduling, and notification requirements set forth in Section 5.12.7 of this Tariff, if their Special Case Resources are available to operate at the direction of the ISO in order to reduce Load from the NYS Transmission System and/or the distribution system for a minimum of four (4) consecutive hours each day, except for those subject to operating limitations established by environmental permits, which will not be required to operate in excess of two (2) hours and which will be derated by the ISO pursuant to ISO Procedures to account for the Load serving equivalence of the hours actually available, 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. 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.

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 will be required to comply with verification and validation procedures set forth in the ISO Procedures. Such procedures will not require metering other than interval billing meters on customer Load or testing other than DMNC or sustained disconnect, as appropriate, unless agreed to by the customer, except that Special Case Resources not called to supply Energy in a Capability Period will be required to run a test once every Capability Period in accordance with the ISO Procedures.

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

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

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

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

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

Transmission Owners that require assistance from enrolled Local Generators larger than 100 kW and Loads capable of being interrupted upon demand for Load relief purposes or as a result of a Local Reliability Rule, shall direct their requests for assistance to the ISO for

implementation consistent with the terms of this section. Within Load Zone J, participation in response to an ISO request to perform made as a result of a request for assistance from a Transmission Owner for less than the total number of Special Case Resources, for Load relief purposes or as a result of a Local Reliability Rule, in accordance with ISO Procedures, shall be voluntary and the responsiveness of the Special Case Resource shall not be taken into account for performance measurement.

5.12.11.1.1 Special Case Resource Average Coincident Load

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

Beginning with the Winter 2011-2012 Capability Period and thereafter, the ISO shall use the average of the highest twenty (20) one-hour peak Loads of the SCR taken from the Load data reported for the Capability Period SCR Load Zone Peak Hours during the Prior Equivalent Capability Period, and taking into account the resource's reported verified Load reduction in a Transmission Owner's demand response program in hours coincident with any of these hours, to create a SCR ACL baseline. In addition, beginning with the Summer 2014 Capability Period, the resource's verified Load reduction in either of the ISO's economic demand response programs (the Day Ahead Demand Response Program and the Demand Side Ancillary Services Program)

in hours coincident with any of the applicable Capability Period SCR Load Zone Peak Hours will be taken into account when creating the SCR ACL. For the Day Ahead Demand Response Program, the verified Load reduction that occurred in response to a DADRP schedule shall be added to the Capability Period SCR Load Zone Peak Hour for which the reduction in response to a DADRP schedule occurred. For the Demand Side Ancillary Services Program, the Load value to be used in calculating the ACL for each hour during the Capability Period SCR Load Zone Peak Hours in which a non-zero Base Point Signal the ISO provides to the resource, shall be the greater of (a) the DSASP Baseline MW value in the interval immediately preceding the first non-zero Base Point Signal in the Capability Period SCR Load Zone Peak Hour and (b) the metered Load of the resource as reported by the RIP for the Capability Period SCR Load Zone Peak Hour. When the non-zero Base Point Signal dispatch of a DSASP resource begins in one hour and continues into consecutive hours, and the consecutive hour is identified as being a Capability Period SCR Load Zone Peak Hour, the DSASP Baseline MW value in effect at the beginning of the dispatch of the non-zero Base Point Signal shall be the MW value used for purposes of determining the applicable Load value for that Capability Period SCR Load Zone Peak Hour, in accordance with the preceding sentence. The ISO will post to its website the Capability Period SCR Load Zone Peak Hours for each zone ninety (90) days prior to the beginning of the Capability Period for which the ACL will be in effect.

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

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

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

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

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

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

5.12.11.1.2 Use of a Provisional Average Coincident Load

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

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

that enrolled the SCR in the Prior Equivalent Capability Period and interval billing meter data for the SCR from the Prior Equivalent Capability Period is not obtainable by the enrolling RIP and not available to be provided to the enrolling RIP by the ISO. The Provisional ACL may be applicable to a SCR for a maximum of three (3) consecutive Capability Periods when enrolled with the same RIP, beginning with the Capability Period in which the SCR is first enrolled by the RIP.

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

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

Any SCR enrolled with a Provisional ACL shall be subject to actual in-period verification. A Verified ACL shall be calculated by the ISO using the top twenty (20) one-hour peak Loads reported for the SCR from the Capability Period SCR Load Zone Peak Hours that are applicable to verify the Provisional ACL in accordance with ISO Procedures and taking into account the resource's reported verified Load reductions in a Transmission Owner's demand response program that are coincident with any of the applicable Capability Period SCR Load Zone Peak Hours. In addition, beginning with the Summer 2014 Capability Period, the resource's verified Load reduction in either of the ISO's economic demand response programs (the Day Ahead Demand Response Program and the Demand Side Ancillary Services Program) in hours coincident with any of the applicable Capability Period SCR Load Zone Peak Hours will be taken into account when creating the SCR Verified ACL. For the Day Ahead Demand Response Program, the verified Load reduction that occurred in response to a DADRP schedule

shall be added to the Capability Period SCR Load Zone Peak Hour for which the reduction in response to a DADRP schedule occurred. For the Demand Side Ancillary Services Program, the Load value to be used in calculating the Verified ACL for each hour during the Capability Period SCR Load Zone Peak Hours in which a non-zero Base Point Signal the ISO provides to the resource, shall be the greater of (a) the DSASP Baseline MW value in the interval immediately preceding the first non-zero Base Point Signal in the Capability Period SCR Load Zone Peak Hour and (b) the metered Load of the resource as reported by the RIP for the Capability Period SCR Load Zone Peak Hour. When the non-zero Base Point Signal dispatch of a DSASP resource begins in one hour and continues into consecutive hours, and the consecutive hour is identified as being a Capability Period SCR Load Zone Peak Hour, the DSASP Baseline MW value in effect at the beginning of the dispatch of the non-zero Base Point Signal shall be the MW value used for purposes of determining the applicable Load value for that Capability Period SCR Load Zone Peak Hour, in accordance with the preceding sentence.

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

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

5.12.11.1.3.1 SCR Change of Load

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

5.12.11.1.3.2 SCR Change of Status

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

Beginning with the Summer 2014 Capability Period, SCRs that were required to perform in the first performance test in the Capability Period in accordance with ISO Procedures and that subsequently report or change a reported SCR Change of Status value after the first performance test in the Capability Period shall be required to demonstrate the performance of the resource against the Net ACL value in the second performance test in the Capability Period. The exceptions to this provision occur when a SCR's eligible Installed Capacity is set to zero

throughout the period of the SCR Change of Status, when a SCR's eligible Installed Capacity is decreased by at least the same kW value as the reported SCR Change of Status, or if a SCR Change of Status is reported, and prior to the second performance test, the SCR returns to the full applicable ACL enrolled prior to the SCR Change of Status. Performance in both performance tests shall be used in calculation of the resource's performance factors and all associated performance factors, deficiencies and penalties. If the RIP fails to report the performance for a resource that was required to perform in the second performance test in the Capability Period: (a) the resource will be assigned a performance of zero (0) for the test hour, and (b) the RIP shall be evaluated for failure to report under Section 5.12.12.2 of this Services Tariff.

5.12.11.1.4 Average Coincident Load of an SCR Aggregation

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

5.12.11.1.5 Use of an Incremental Average Coincident Load

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

For SCRs with a total Load increase equal to or greater than twenty (20) percent and less than thirty (30) percent of the applicable ACL, the RIP may enroll the SCR with an Incremental ACL provided that the eligible Installed Capacity does not increase from the prior enrollment months within the same Capability Period and prior to enrollment with an Incremental ACL. If the SCR is enrolled with an Incremental ACL and it is the first month of the SCR's enrollment in the applicable Capability Period, the enrolled eligible Installed Capacity value shall not exceed

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

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

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

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

of the non-zero Base Point Signal shall be the MW value used for purposes of determining the applicable Load value for that Monthly SCR Load Zone Peak Hour, in accordance with the preceding sentence. The Verified ACL shall be the average of the two (2) highest Monthly ACLs during the Capability Period in which the SCR was enrolled with an Incremental ACL within the same Capability Period.

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

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

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

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

5.12.11.2 Existing Municipally-Owned Generation

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

5.12.11.3 Energy Limited Resources

An Energy Limited Resource may, consistent with the deliverability requirements set forth in Attachment X and Attachment S to the ISO OATT, qualify as an Installed Capacity Supplier if it Bids its Installed Capacity Equivalent into the Day-Ahead Market each day and if it

is able to provide the Energy equivalent of the Unforced Capacity for at least four (4) consecutive hours each day. Energy Limited Resources shall also Bid a Normal Upper Operating Limit or Emergency Upper Operating Limit, as applicable, designating their desired operating limits. Energy Limited Resources that are not scheduled in the Day-Ahead Market to operate at a level above their bid-in upper operating limit, may be scheduled in the RTC, or may be called in real-time pursuant to a manual intervention by ISO dispatchers, who will account for the fact that Energy Limited Resource may not be capable of responding.

5.12.11.4 Intermittent Power Resources

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

5.12.12 Sanctions Applicable to Installed Capacity Suppliers and Transmission Owners

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

sole discretion. Installed Capacity Suppliers and Transmission Owners may challenge any sanction imposed by the ISO pursuant to the ISO Dispute Resolution Procedures.

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

5.12.12.1 Sanctions for Failing to Provide Required Information

If (i) an Installed Capacity Supplier fails to provide the information required by Sections 5.12.1.1, 5.12.1.2, 5.12.1.3, 5.12.1.4, 5.12.1.7 or 5.12.1.8 of this Tariff in a timely fashion, or (ii) a Supplier of Unforced Capacity from External System Resources located in an External Control Area or from a Control Area System Resource that has agreed not to Curtail the Energy associated with such Installed Capacity, or to afford it the same Curtailment priority that it affords its own Control Area Load, fails to provide the information required for certification as an Installed Capacity Supplier established in the ISO Procedures, the ISO may take the following actions: On the first day that required information is late, the ISO shall notify the Installed Capacity Supplier that required information is past due and that it reserves the right to impose financial sanctions if the information is not provided by the end of the following day. Starting on the third day that the required information is late, the ISO may impose a daily financial sanction of up to the higher of \$500 or \$5 per MW of Installed Capacity that the Generator, System Resource, or Control Area System Resource in question is capable of providing. Starting on the tenth day that the required information is late, the ISO may impose a daily financial sanction of up to the higher of \$1000 or \$10 per MW of Installed Capacity that the Generator, System Resource, or Control Area System Resource in question is capable of providing.

If an Installed Capacity Supplier fails to provide the information required by Subsection 5.12.1.5 of this Tariff in a timely fashion, the ISO may take the following actions: On the first

calendar day that required information is late, the ISO shall notify the Installed Capacity Supplier that required information is past due and that it reserves the right to impose financial sanctions if the information is not provided by the end of that first calendar day. Starting on the second calendar day that the required information is late, the ISO may impose a daily financial sanction up to the higher of \$500 or \$5 per MW of Installed Capacity that the Generator, System Resource, or Control Area System Resource in question is capable of providing.

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

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

On any day in which an Installed Capacity Supplier fails to comply with the scheduling, bidding, or notification requirements of Sections 5.12.1.6 or 5.12.1.10, or with Section 5.12.7 of this Tariff, or in which a Supplier of Installed Capacity from External System Resources or Control Area System Resources located in an External Control Area that has agreed not to Curtail the Energy associated with such Installed Capacity, or to afford it the same Curtailment priority that it affords its own Control Area Load, fails to comply with scheduling, bidding, or notification requirements for certification as an Installed Capacity Supplier established in the ISO Procedures, the ISO may impose a financial sanction up to the product of a deficiency charge (pro-rated on a daily basis) 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 whole 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, if an Installed Capacity Supplier fails to comply with the scheduling, bidding, or notification requirements of Sections 5.12.1.6 or 5.12.1.10, or with Section 5.12.7 of this Tariff, or if an Installed Capacity Supplier of Unforced Capacity from External System Resources or from a Control Area System Resource located in an External Control Area that has agreed not to curtail the Energy associated with such Unforced Capacity, or to afford it the same curtailment priority that it affords its own Control Area Load, 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 Transactions associated with NYCA Installed Capacity Suppliers, 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.

If the Installed Capacity Supplier is a Responsible Interface Party that enrolled a SCR with an Incremental ACL in accordance with this Services Tariff, and also reported an increase to the Installed Capacity the SCR has eligible to sell after the first performance test in the

Capability Period, the ISO may impose an additional financial sanction due to the failure of the RIP to report the required performance of the SCR against the Net ACL value in the second performance test in the Capability Period. This sanction shall be the value of the reported increase in the eligible Installed Capacity associated with the SCR that was sold by the RIP in each month of the Capability Period, during which the reported increase was in effect, multiplied by up to one and one-half times the applicable Market-Clearing Price of Unforced Capacity determined in the ICAP Spot Market Auction for each such month.

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

If a RIP fails to provide the information required by Section 5.12.11.1.3 of this Services Tariff in accordance with the ISO Procedures for reporting a Qualified Change of Status Condition, and the ISO determines that a SCR Change of Status occurred within a Capability Period, the ISO may impose a financial sanction equal to the difference, if positive, between the

enrolled ACL and the maximum one hour metered Load for the month multiplied by up to one-half times the applicable Market-Clearing Price of Unforced Capacity determined in the ICAP Spot Market Auction for each month the Installed Capacity Supplier is deemed to have a shortfall in addition to the corresponding shortfall penalty as provided in Section 5.14.2.

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

15.3 Rate Schedule 3 - Payments for Regulation Service

This Rate Schedule applies to Suppliers that provide Regulation Service to the ISO. A Behind-the-Meter Net Generation Resource that is comprised of more than one generating unit that is dispatched as a single aggregate unit is not qualified to provide Regulation Service to the ISO. Transmission Customers will purchase Regulation Service from the ISO under the ISO OATT.

15.3.1 Obligations of the ISO and Suppliers

15.3.1.1 The ISO shall:

- (a) Establish Regulation Service criteria and requirements in the ISO Procedures to ensure that Suppliers follow changes in Load consistent with the Reliability Rules;
- (b) Provide RTD Base Point Signals and AGC Base Point Signals to Suppliers providing Regulation Service to direct their output;
- (c) Establish criteria in the ISO Procedures that Suppliers must meet to qualify, or re-qualify, to supply Regulation Service;
- (d) Establish minimum metering requirements and telecommunication capability required for a Supplier to be able to respond to AGC Base Point Signals and RTD Base Point Signals sent by the ISO;
- (e) Select Suppliers to provide Regulation Service in the Day-Ahead Market and Real-Time Market and establish Regulation Service schedules, in MWs of Regulation Capacity, for each scheduled Regulation Supplier in the Day-Ahead and Real-Time Markets, as described in Section 15.3.2 of this Rate Schedule;

- (f) Pay Suppliers for providing Regulation Service as described in this Rate Schedule;
- (g) Monitor Suppliers' performance to ensure that they provide Regulation Service as required, as described in Section 15.3.3 of this Rate Schedule; and
- (h) Take into account the speed and accuracy of regulation resources in determining reserve requirements for Regulation Service.

15.3.1.2 Each Supplier shall:

- (a) Register with the ISO the Regulation Capacity its resources are qualified to bid in the Regulation Services market;
- (b) Provide the ISO with the Resource's Regulation Capacity Response Rate and the Resource's Regulation Movement Response Rate;
- (c) Offer only Resources that are; (i) ISO-Committed Flexible or Self-Committed Flexible, provided however that Demand Side Resources shall be offered as ISO-Committed Flexible; within the dispatchable portion of their operating range, and; (ii) able to respond to AGC Base Point Signals sent by the ISO pursuant to the ISO Procedures, to provide Regulation Service;
- (d) Not use, contract to provide, or otherwise commit Regulation Capacity that is selected by the ISO to provide Regulation Service to provide Energy or Operating Reserves to any party other than the ISO;
- (e) Pay any charges imposed under this Rate Schedule;
- (f) Ensure that all of its Resources that are selected to provide Regulation Service comply with Base Point Signals issued by the ISO at all times pursuant to the ISO Procedures; and ensure that all of its Resources that are selected to provide

Regulation Service comply with all criteria and ISO Procedures that apply to providing Regulation Service.

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

- (a) The ISO shall select Suppliers in the Day-Ahead Market to provide Regulation Service for each hour in the following Dispatch Day and in the Real-Time Market to provide Regulation Service for each interval in the Dispatch Day, from those that have Bid to provide Regulation Service from Resources and that meet the qualification standards and criteria established in Section 15.3.1 of this Rate Schedule and in the ISO Procedures.
- (b) In order to schedule Suppliers in the Day-Ahead Market to provide Regulation Service for each hour in the following Dispatch Day, the ISO shall use, as each Supplier's Regulation Service Bid price, the sum of: a) the Supplier's Day-Ahead Regulation Capacity Bid Price and b) the product of the Supplier's Day-Ahead Regulation Movement Bid Price and the applicable Regulation Movement Multiplier.
- (c) In order to schedule Suppliers in the Real-Time Market to provide Regulation Service for each interval in the Dispatch Day the ISO shall use, as each Supplier's Regulation Service Bid price, the sum of: a) the Supplier's Real-Time Regulation Capacity Bid Price and b) the product of the Supplier's Real-Time Regulation Movement Bid Price and the applicable Regulation Movement Multiplier.
- (d) The ISO shall establish separate Regulation Capacity Market Prices in the Day-Ahead Market and the Real-Time Market under Sections 15.3.4, 15.3.5 and 15.3.7

of this Rate Schedule and shall establish a Real-Time Regulation Movement Market Price under Section 15.3.5.1 of this Rate Schedule. The ISO shall also compute Regulation Revenue Adjustment Payments and Regulation Revenue Adjustment Charges under Section 15.3.6 of this Rate Schedule.

15.3.2.1 Bidding Process

- (a) A Supplier may submit a Bid in the Day- Ahead Market or the Real-Time Market to provide Regulation Service from eligible Resources, provided, however, that Bids submitted by Suppliers that are attempting to re-qualify to provide Regulation Service, after being disqualified pursuant to Section 15.3.3 of this Rate Schedule 3, may be limited by the ISO pursuant to ISO Procedures.
- (b) Bids rejected by the ISO may be modified and resubmitted by the Supplier to the ISO in accordance with the terms of the ISO Tariff.
- (c) Each Bid shall contain the following information: (i) the maximum amount of capability (in MW) that the Resource is willing to provide as Regulation Capacity; (ii) the Supplier's Bid Price (in \$/MW) for Regulation Capacity; (iii) the Suppliers Bid Price (in \$/MW) for Regulation Movement; and (iv) the physical location and name or designation of the Resource.
- (d) Regulation Service Offers from Limited Energy Storage Resources: The ISO may reduce the real-time Regulation Service offer (in MWs) from a Limited Energy Storage Resource to account for the Energy storage capacity of such Resource.

15.3.3 Monitoring Regulation Service Performance and Performance Related Payment Adjustments

- (a) The ISO shall establish (i) Resource performance measurement criteria; (ii) procedures to disqualify Suppliers whose Resources consistently fail to meet those criteria; and (iii) procedures to re-qualify disqualified Suppliers, which may include a requirement to first demonstrate acceptable performance for a time.
- (b) The ISO shall establish and implement a Performance Tracking System to monitor the performance of Suppliers that provide Regulation Service. The ISO shall develop performance indices, which may vary with Control Performance, as part of the ISO Procedures. The ISO shall use the values provided by the Performance Tracking System to adjust settlements for real-time Regulation Movement pursuant to Section 15.3.5.4.1 and to compute a performance charge to apply to real-time Regulation Service providers pursuant to Section 15.3.5.4.2 of this Rate Schedule.
- (c) Resources that consistently fail to perform adequately may be disqualified by the ISO, pursuant to ISO Procedures.

15.3.4 Regulation Service Settlements - Day-Ahead Market

15.3.4.1 Calculation of Day-Ahead Market Prices

The ISO shall calculate a Day-Ahead Regulation Capacity Market Price for each hour of the following day. The Day-Ahead Regulation Capacity Market Price for each hour shall equal the Day-Ahead Shadow Price of the ISO's Regulation Service constraint for that hour, which shall be established under the ISO Procedures, minus the product of i) the Day-Ahead Regulation Movement Bid Price of the marginal Resource selected to provide Regulation Service; and ii) the applicable Regulation Movement Multiplier. Day-Ahead Shadow Prices will be calculated by

the ISO's SCUC. Each hourly Day-Ahead Shadow Price shall equal the marginal Bid cost of scheduling Resources to provide additional Regulation Service in that hour, including any impact on the Bid Production Cost of procuring Energy or Operating Reserves that would result from procuring an increment of Regulation Service in that hour, as calculated during the fifth SCUC pass described in Section 17.1.3 of Attachment B to this ISO Services Tariff. As a result, the Shadow Price shall include the Day-Ahead Regulation Service Bids of the marginal Resource selected to provide Regulation Service, plus any margins on the sale of Energy or 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 less Energy or 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 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 of Energy or 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 less Energy or Operating Reserves (or the applicable price on the Regulation Service Demand Curve during shortage conditions). Shadow Prices consistent with the Regulation Service Demand Curves described in Section 15.3.7 of this Rate Schedule will ensure that Regulation Service is not scheduled at a cost greater than the Demand Curve indicates.

During any period when the ISO sets Resources' Regulation Service Schedules to zero, pursuant to Section 15.3.8 of this Rate Schedule, the Real-Time Regulation Capacity Market

Price and the Real-Time Regulation Movement Market Price shall automatically be set to zero, which shall be the price used for real-time balancing and settlement purposes.

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

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

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

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

Market Price in that interval; (b) the Regulation Movement instructed during the interval, and (c) the performance factor calculated for that Regulation Service provider in that interval pursuant to Section 15.3.5.4.1.

- (d) The ISO shall assess a performance charge, pursuant to Section 15.3.5.4.2 to all Suppliers of Regulation Service with real-time Regulation Service schedules.
- (e) No payments shall be made to any Supplier providing Regulation Service in excess of the amount of Regulation Service scheduled by the ISO in the Real Time Market, except to the extent that a Supplier is directed to provide the excess amount by the ISO.

15.3.5.3 Other Real-Time Regulation Service Payments

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

A Supplier that bids on behalf of a Regulation Service provider may also be eligible for a Day-Ahead Margin Assurance Payment pursuant to Section 4.6.5 and Attachment J of this ISO Services Tariff.

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

15.3.5.4.1 Performance-Based Adjustment to Payments for Regulation Service Suppliers

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

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

Where:

K_{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.

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

- $DAMPreg_i$ = is the applicable Regulation Capacity Market Price (in \$/MW), in the Day-Ahead Market, as established by the ISO pursuant to Section 15.3.4.1 of this Rate Schedule for the hour that includes RTD interval i ;
- $RTMPreg_i$ = is the applicable Regulation Capacity Market Price (in \$/MW), in the Real-Time Market as established by the ISO under Section 15.3.5.1 of this Rate Schedule in RTD interval i ;
- $RTRcap_i$ = is the Regulation Capacity (in MW) offered by the Resource and selected by the ISO in the Real-Time Market in RTD interval i ;
- $RTRinccap_i$ = 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 Generators Providing Regulation Service

15.3.6.1 Energy Settlements

- A. For any interval in which a Generator that is not a Limited Energy Storage Resource is providing Regulation Service, it shall receive a settlement payment for Energy consistent with a real-time Energy injection equal to the lower of its actual generation or its AGC Base Point Signal. Demand Side Resources providing Regulation Service shall not receive a settlement payment for Energy.
- B. For any hour in which a Limited Energy Storage Resource 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 in hour h minus the amount of Energy withdrawn by that Limited Energy Storage Resource in hour h

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

15.3.6.2 Additional Payments/Charges

For any interval in which a Generator 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.

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

For any interval in which a Generator that is providing Regulation Service receives an AGC Base Point Signal that is higher than its RTD Base Point Signal, it shall receive or pay a RRAP or RRAC calculated under the terms of this subsection. If the Energy Bid Price of such a Generator is higher than the LBMP at its location in that interval, the Generator shall receive a RRAP. Conversely, for any interval in which such a Generator’s Energy Bid Price is lower than the LBMP at its location at that interval, the Generator 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 Generator shall receive a RRAP. If it is negative then the Generator shall be subject to a RRAC. For purposes of applying this formula, whenever the Generator's actual Bid exceeds the applicable LBMP the "Bid" term shall be set at a level equal to the lesser of the Generator's actual Bid or its reference Bid plus \$100/MWh. Demand Side Resources providing Regulation Service shall not be eligible for a RRAP and not liable for an RRAC.

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 Generator 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 Generator is higher than the LBMP at its location in that interval, the Generator shall be assessed a RRAC. Conversely, for any interval in which such a Generator's Energy Bid Price is lower than the LBMP at its location in that interval, the Generator 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 Generator shall receive a RRAP. If it is negative then the Generator shall be subject to a RRAC. For purposes of this formula, whenever the Generator's actual Bid is lower than the applicable LBMP the "Bid" term shall be set at a level equal to the higher of the Generator's actual Bid or its reference Bid minus \$100/MWh.

Demand Side Resources providing Regulation Service shall not be eligible for a RRAP and not liable for an RRAC.

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 included in Section 15.3A.2.3 of this Rate Schedule, that is not providing Regulation Service and that persistently operates at a level below its Energy schedule 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:

$$\text{Persistent undergeneration charge} = \text{Energy Difference} \times \text{Max} (\text{MPRC}_{\text{DAM}}, \text{MPRC}_{\text{RT}}) \times \text{Length of Interval in seconds}/3600 \text{ seconds}$$

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 as its fuel, for which the ISO has imposed a Wind Output Limit after October 31, 2009, or after February 1, 2010 for an Intermittent Power Resource that depends on wind as its fuel in commercial operation before 2006 with nameplate capacity of 30 MWs or less, 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.

Overgeneration charges per interval shall be calculated as follows:

$$\text{Overgeneration charge} = \text{Energy Difference} \times \text{Max} (\text{MPRC}_{\text{DAM}}, \text{MPRC}_{\text{RT}}) \times \text{Length of Interval in seconds}/3600 \text{ seconds}$$

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 Intermittent Power 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 Supplier's 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.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, 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 topping or extraction turbine Generators utilized in replacing or repowering existing steam supplies from such units (in accordance with good engineering and economic design) that cannot follow schedules, up to a maximum total of 523 MW of such units;
- 15.3A.2.3 Intermittent Power Resources that depend on wind as their fuel and Limited Control Run of River Hydro Resources within the NYCA in operation on or before November 18, 1999, plus up to an additional 3300 MW of such Generators;
- 15.3A.2.4 Intermittent Power Resources that depend on landfill gas or solar energy as their fuel;
- 15.3A.2.5 Capacity Limited Resources and Energy Limited Resources to the extent that their real-time Energy injections are equal to or greater than their bid-in upper operating limits but are less than their Real-Time Scheduled Energy Injections;
- 15.3A.2.6 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.2.7 Generators operating during a Testing Period.

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

The ISO shall define requirements for Spinning Reserve, which may be met only by Suppliers that are eligible, under Section 15.4.1.2 of this Rate Schedule, to provide Spinning Reserve; 10-Minute Reserve, which may be met by Suppliers that are eligible to provide either Spinning Reserve or 10-Minute Non-Synchronized Reserve; and 30-Minute Reserve, which may be met by Suppliers that are eligible to provide any Operating Reserve product. The ISO shall also define locational requirements for Spinning Reserve, 10-Minute Reserve, and 30-Minute Reserve located East of Central-East, in Southeastern New York 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, and requirements for Operating Reserve located on Long Island may only be met by eligible Suppliers located on Long Island. Each of these Operating Reserve requirements shall be defined consistent with the Reliability Rules and other applicable reliability standards. The ISO shall also establish Scarcity Reserve Requirements in the Real-Time Market pursuant to Section 15.4.6.2 of this Rate Schedule, which may be met by Suppliers eligible to provide 30-Minute Reserve. Scarcity Reserve Requirements may only be met by eligible Suppliers that are located in the Scarcity Reserve Region associated with a given Scarcity Reserve Requirement. The ISO shall select Suppliers of Operating Reserves products to meet these requirements, including the locational Operating Reserves requirements and Scarcity Reserve Requirements, as part of its overall co-optimization process.

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

15.4.1.2 Supplier Eligibility Criteria

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

15.4.1.2.1 Spinning Reserve:

Suppliers that are ISO Committed Flexible or Self-Committed Flexible, are operating within the dispatchable portion of their operating range, are capable of responding to ISO instructions to change their output level within ten minutes, and that meet the criteria set forth in the ISO Procedures shall be eligible to supply Spinning Reserve (except for Demand Side Resources that are Local Generators and Behind-the-Meter Net Generation Resources that are comprised of more than one generating unit and dispatched as a single aggregate unit).

15.4.1.2.2 10-Minute Non-Synchronized Reserve:

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

15.4.1.2.3 30-Minute Reserve:

Generators, except Behind-the-Meter Net Generation Resources that are comprised of more than one generating unit and dispatched as a single aggregate unit, that are ISO-Committed Flexible or Self-Committed Flexible and operating within the dispatchable portion of their

operating range and Demand Side Resources, that are not Local Generators, that are capable of reducing their Energy usage within thirty (30) minutes shall be eligible to supply synchronized 30-Minute Reserves. (i) Off-line Generators that are capable of starting, synchronizing, and increasing their output level within thirty (30) 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 thirty (30) minutes, and (iii) Demand Side Resources that are capable of reducing their Energy usage within thirty (30) minutes, that meet the criteria set forth in the ISO Procedures shall be eligible to supply non-synchronized 30-Minute Reserves.

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

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

15.4.1.3 Other Supplier Requirements

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

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

Generators or Demand Side Resources that are selected to provide Operating Reserve in the Day-Ahead Market or any supplemental commitment may increase their Incremental Energy Bids or Demand Reduction Bids for portions of their Resources that have been scheduled

through those processes; provided however, that they are not otherwise prohibited from doing so pursuant to other provisions of the ISO's Tariffs. They may not, however, reduce their Day-Ahead Market or supplemental commitments in real-time except to the extent that they are directed to do so by the ISO. Generators and Demand Side Resources may enter into alternate sales arrangements utilizing any Capacity that has not been scheduled to provide Operating Reserve.

15.4.2 General Day-Ahead Market Rules

15.4.2.1 Bidding and Bid Selection

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

The ISO may schedule Suppliers that make themselves available to provide Operating Reserves up to the following maximum Operating Reserve levels: (i) for Spinning Reserves, the Resource's emergency response rate multiplied by ten; (ii) for 10-Minute Non-Synchronized Reserves, or for non-synchronized 30-Minute Reserves, the Resource's UOLN or UOLE, 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 Resource's emergency response rate multiplied by twenty.

However, the sum of the amount of Energy or Demand Reduction 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 UOLN or UOLE, whichever is applicable.

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 Article 4.2 of, and Attachment D to, this ISO Services Tariff. As part of the co-optimization process, the ISO shall determine how much of each Operating Reserves product particular Suppliers will be required to provide in light of the Reliability Rules and other applicable reliability standards, including the locational Operating Reserves requirements specified above.

15.4.2.2 ISO Notice Requirement

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

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

Suppliers that are scheduled Day-Ahead to provide Operating Reserves shall either provide Operating Reserve, Energy or Demand Reductions in real-time when scheduled by the ISO in all hours for which they have been selected to provide Operating Reserve and are physically capable of doing so. However, Suppliers that are scheduled Day-Ahead to provide Operating Reserves and have startup periods of two hours or less may advise the ISO no later than three hours prior to the first hour of their Day-Ahead schedule that they will not be available to provide Operating Reserves or Energy in real-time under normal conditions. Such Suppliers

will be required to settle their Day-Ahead schedule at real-time prices pursuant to Section 15.4.6.3 of this Rate Schedule. The only restriction on Suppliers' ability to exercise this option is that all Suppliers with Day-Ahead Operating Reserves schedules must make the scheduled amount of Capacity available to the ISO for dispatch in the RTD if the ISO initiates a Supplemental Resource Evaluation.

15.4.3 General Real-Time Market Rules

15.4.3.1 Bid Selection

The ISO will automatically select Operating Reserves Suppliers in real-time from eligible Resources, that submit Real-Time Bids pursuant to Section 4.4 of, and Attachment D to, this ISO Services Tariff. Each Supplier will automatically be assigned a real-time Operating Reserves Availability bid of \$0/MW for the quantity of Capacity that it makes available to the ISO in its Real-Time Bid. The ISO may schedule Suppliers that make themselves available to provide Operating Reserves up to the following maximum Operating Reserve levels: (i) for Spinning Reserves, the Resource's emergency response rate multiplied by ten; (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 Resource's emergency response rate multiplied by twenty. However, the sum of the amount of Energy or Demand Reduction, that each Resource is scheduled to provide, the amount of Regulation Service it is scheduled to provide, and the amount of each Operating Reserves product it is scheduled to provide shall not exceed its UOL_N or UOL_E , whichever is applicable.

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

15.4.3.2 ISO Notice Requirement

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

15.4.3.3 Obligation to Make Resources Available to Provide Operating Reserves

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

15.4.3.4 Activation of Operating Reserves

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

15.4.3.5 Performance Tracking and Supplier Disqualifications

When a Supplier committed to supply Operating Reserves is activated, the ISO shall measure and track its actual Energy production or its Demand Reduction against its expected performance in real-time. The ISO may disqualify Suppliers that consistently fail to provide Energy or Demand Reduction 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 four locations: (i) West of Central-East (“West” or “Western”); (ii) East of Central-East excluding Southeastern New York (“Eastern”); (iii) Southeastern New York excluding Long Island (“Southeastern”); and (iv) Long Island (“L.I.”). The ISO will thus calculate twelve 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 L.I. 30-Minute Reserves = SP1 + SP4 + SP7 + SP10

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

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

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, or L.I. 30-Minute Reserve requirement constraint for the hour
- SP5 = Shadow Price for Eastern, Southeastern, or L.I. 10-Minute Reserve requirement constraint for the hour
- SP6 = Shadow Price for Eastern, Southeastern, or L.I. Spinning Reserve requirement constraint for the hour
- SP7 = Shadow Price for Southeastern, or L.I. 30-Minute Reserve requirement constraint for the hour
- SP8 = Shadow Price for Southeastern, or L.I. 10-Minute Reserve requirement constraint for the hour
- SP9 = Shadow Price for Southeastern, or L.I. Spinning Reserve requirement constraint for the hour
- SP10 = Shadow Price for Long Island 30-Minute Reserve requirement constraint for the hour
- SP11 = Shadow Price for Long Island 10-Minute Reserve requirement constraint for the hour
- SP12 = Shadow Price for Long Island Spinning Reserve requirement constraint for the hour

Day-Ahead locational Shadow Prices will be calculated by SCUC. Each hourly Day-Ahead Shadow Price for each Operating Reserves requirement shall equal the marginal Bid cost of scheduling Resources to provide additional Operating Reserves to meet that requirement in that hour, including any impact on the Bid Production Cost of procuring Energy or Regulation Service that would result from procuring an increment of Operating Reserve to meet the requirement in that hour, as calculated during the fifth SCUC pass described in Section 17.1.3 of Attachment B to this Services Tariff. As a result, the Shadow Price for each Operating Reserves

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

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

15.4.5.2 Other Day-Ahead Payments

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

15.4.6 Operating Reserve Settlements – Real-Time Market

15.4.6.1 Calculation of Real-Time Market Clearing Prices

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

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

Market clearing price for Western 30-Minute Reserves = SP1

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

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

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

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

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

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

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

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

Market clearing price for L.I. 30-Minute Reserves = $SP1 + SP4 + SP7 + SP10$

Market clearing price for L.I. 10-Minute Non-Synchronized Reserves = $SP1 + SP2 + SP4 + SP5 + SP7 + SP8 + SP10 + SP11$

Market clearing price for L.I. Spinning Reserves = $SP1 + SP2 + SP3 + SP4 + SP5 + SP6 + SP7 + SP8 + SP9 + SP10 + SP11 + SP12$

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, or L.I. 30-Minute Reserve requirement constraint and, if applicable, Scarcity Reserve Requirement constraint for the interval

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

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

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

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

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

SP10 = Shadow Price for Long Island 30-Minute Reserve requirement constraint and, if applicable, Scarcity Reserve Requirement constraint for the interval

SP11 = Shadow Price for Long Island 10-Minute Reserve requirement constraint for the interval

SP12 = 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 third RTD pass described in Section 17.1.2.1.2.3 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; or
 - iv. 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 SP10. SP10 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 or J, but does not include Load Zones A, B, C, D, E or F and Section 15.4.6.1.1(a)(iii) of this Rate Schedule is not applicable, then the Shadow Price for the Scarcity Reserve Requirement

shall be included in SP7 for each of the Load Zones included in the Scarcity Reserve Region. This SP7 value shall be utilized in the same manner as described in the formulae above in calculating Real-Time Market clearing prices for each of the Load Zones included in the Scarcity Reserve Region.

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

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

The applicable value of the Expected EDRP/SCR MW for each Load Zone included in a Scarcity Reserve Region to be used in calculating the Scarcity Reserve Requirement is dependent upon whether the Load reduction for a given interval is deemed voluntary or mandatory for purposes of calculating the Scarcity Reserve Requirement, as further described below. If the ISO has satisfied the notification requirements set forth in Section 5.12.11.1 of this ISO Services Tariff for the SCRs within any Load Zone for any hour encompassed by the EDRP/SCR activation(s) for the day at issue, the Load reduction for all intervals encompassed by such activation(s) are deemed to be mandatory for the purposes of calculating any Scarcity Reserve Requirement only and the corresponding value for a mandatory Load reduction is used

for SCRs in determining any Scarcity Reserve Requirement. In all other circumstances not encompassed by the preceding sentence, the Load reduction for all intervals encompassed by such EDRP/SCR activation(s) are deemed to be voluntary for the day at issue and the corresponding value for a voluntary Load reduction is used for SCRs in determining any Scarcity Reserve Requirement. For EDRP, Load reduction is deemed to be voluntary in all intervals and the value for EDRP included in the Expected EDRP/SCR MW value for each Load Zone reflects the voluntary nature of the Load reduction.

15.4.6.3 Operating Reserve Balancing Payments

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

- (a) When the Supplier's real-time Operating Reserves schedule is less than its Day-Ahead Operating Reserves schedule, the Supplier shall pay a charge for the imbalance equal to the product of: (i) the Real-Time Market clearing price for the relevant Operating Reserves Product in the relevant location or Scarcity Reserve Region; and (ii) the difference between the Supplier's Day-Ahead and real-time Operating Reserves schedules.
- (b) When the Supplier's real-time Operating Reserves schedule is greater than its Day-Ahead Operating Reserves schedule, the ISO shall pay the Supplier an amount to compensate it for the imbalance equal to the product of: (i) the Real-Time Market clearing price for the relevant Operating Reserve product in the relevant location or Scarcity Reserve Region; and (ii) the difference between the Supplier's Day-Ahead and real-time Operating Reserves schedules.

15.4.6.4 Other Real-Time Payments

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

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

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

15.4.7 Operating Reserve Demand Curves and Scarcity Reserve Demand Curve

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

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

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

Load Zones included in the Scarcity Reserve Region belong. The ISO will then define an Operating Reserves demand curve for that hour corresponding to each Operating Reserves requirement as follows:

- (a) Total Spinning Reserves: For quantities of Operating Reserves meeting the total Spinning Reserves requirement that are less than or equal to the target level for that locational requirement, the price on the total Spinning Reserves demand curve shall be \$775/MW. For all other quantities, the price on the total Spinning Reserves demand curve shall be \$0/MW.
- (b) Eastern, Southeastern or Long Island Spinning Reserves: For quantities of Operating Reserves meeting the Eastern, Southeastern 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 or Long Island Spinning Reserves demand curve shall be \$25/MW. For all other quantities, the price on the Eastern, Southeastern or Long Island Spinning Reserves demand curve shall be \$0/MW.
- (c) Southeastern or Long Island Spinning Reserves: For quantities of Operating Reserves meeting the Southeastern 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 or Long Island Spinning Reserves demand curve shall be \$25/MW. For all other quantities, the price on the Southeastern or Long Island Spinning Reserves demand curve shall be \$0/MW.
- (d) 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.

- (e) Total 10-Minute Reserves: For quantities of Operating Reserves meeting the total 10-minute reserves requirement that are less than or equal to the target level for that locational requirement, the price on the total 10-minute reserves demand curve shall be \$750/MW. For all other quantities, the price on the total 10-minute reserves demand curve shall be \$0/MW.
- (f) Eastern, Southeastern or Long Island 10-Minute Reserves: For quantities of Operating Reserves meeting the Eastern, Southeastern or Long Island 10-minute reserves requirement that are less than or equal to the target level for that locational requirement, the price on the Eastern, Southeastern or Long Island 10-minute reserves demand curve shall be \$775/MW. For all other quantities, the price on the Eastern, Southeastern or Long Island 10-minute reserves demand curve shall be \$0/MW.
- (g) Southeastern or Long Island 10-Minute Reserves: For quantities of Operating Reserves meeting the Southeastern 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 or Long Island 10-Minute Reserves demand curve shall be \$25/MW. For all other quantities, the price on the Southeastern or Long Island 10-Minute Reserves demand curve shall be \$0/MW.
- (h) Long Island 10-Minute Reserves: For quantities of Operating Reserves meeting the Long Island 10-minute reserves requirement that are less than or equal to the

target level for that locational requirement, the price on the Long Island 10-minute reserves demand curve shall be \$25/MW. For all other quantities, the price on the Long Island 10-minute reserves demand curve shall be \$0/MW.

- (i) Total 30-Minute Reserves: For quantities of Operating Reserves meeting the total 30-Minute Reserves requirement that are less than or equal to the target level for that locational requirement minus 955 MW, the price on the total 30-Minute Reserves demand curve shall be \$750/MW. For quantities of Operating Reserves meeting the total 30-Minute Reserves requirement that are less than or equal to the target level for that locational requirement minus 655 MW but that exceed the target level for that locational requirement minus 955 MW, the price on the total 30-Minute Reserves demand curve shall be \$200/MW; provided, however, that during each real-time interval in which the ISO has established a Scarcity Reserve Requirement, the price on the total 30-Minute Reserves demand curve shall be increased to \$500/MW. For quantities of Operating Reserves meeting the total 30-Minute Reserves requirement that are less than or equal to the target level for that locational requirement minus 300 MW but that exceed the target level for that locational requirement minus 655 MW, the price on the total 30-Minute Reserves demand curve shall be \$100/MW; provided, however, that during each real-time interval in which the ISO has established a Scarcity Reserve Requirement, the price on the total 30-Minute Reserves demand curve shall be increased to \$500/MW. For quantities of Operating Reserves meeting the total 30-Minute Reserves requirement that are less than or equal to the target level for that locational requirement but that exceed the target level for that locational

requirement minus 300 MW, the price on the total 30-Minute Reserves demand curve shall be \$25/MW; provided, however, that during each real-time interval in which the ISO has established a Scarcity Reserve Requirement, the price on the total 30-Minute Reserves demand curve shall be increased to \$500/MW. For all other quantities, the price on the total 30-Minute Reserves demand curve shall be \$0/MW. However, the ISO will not schedule more total 30-Minute Reserves than the level defined by the requirement for that hour.

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

Reserves locational requirement plus the Scarcity Reserve Requirement for that interval.

- (j) Eastern, Southeastern or Long Island 30-Minute Reserves: For quantities of Operating Reserves meeting the Eastern, Southeastern or Long Island 30-Minute Reserves requirement that are less than or equal to the target level for that requirement, the price on the Eastern, Southeastern or Long Island 30-Minute Reserves demand curve shall be \$25/MW. For all other quantities, the price on the Eastern, Southeastern 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 or Long Island 30-Minute Reserves shall be as follows: For quantities of Operating Reserves meeting the Eastern, Southeastern or Long Island 30-Minute Reserves locational requirement target level plus the Scarcity Reserve Requirement (“Eastern scarcity target level”) that are less than or equal to the Eastern scarcity target level minus an amount equal to the Eastern, Southeastern or Long Island 30-Minute Reserves locational requirement target, the price on the Eastern, Southeastern or Long Island 30-Minute Reserves demand curve shall be \$500/MW. For the quantities of Operating Reserves meeting the Eastern scarcity target level that are less than or equal to the Eastern scarcity target level but exceed the Eastern scarcity target level minus an amount equal to the Eastern, Southeastern or Long Island 30-

Minute Reserves locational requirement target level, the price on the Eastern, Southeastern or Long Island 30-Minute Reserves demand curve shall be \$25/MW. For all other quantities, the price on the Eastern, Southeastern or Long Island 30-Minute Reserves demand curve shall be \$0/MW.

- (k) Southeastern or Long Island 30-Minute Reserves: For quantities of Operating Reserves meeting the Southeastern or Long Island 30-Minute Reserves requirement that are less than or equal to the target level for that requirement, the price on the Southeastern or Long Island 30-Minute Reserves demand curve shall be \$500/MW. For all other quantities, the price on the Southeastern 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 or Long Island 30-Minute Reserves shall be as follows: For quantities of Operating Reserves meeting the Southeastern or Long Island 30-Minute Reserves locational requirement target level plus the Scarcity Reserve Requirement (“Southeastern scarcity target level”) that are less than or equal to the Southeastern scarcity target level, the price on the Southeastern or Long Island 30-Minute Reserves demand curve shall be \$500/MW. For all other quantities, the price on the Southeastern or Long Island 30-Minute Reserves demand curve shall be \$0/MW.

- (l) Long Island 30-Minute Reserves: For quantities of Operating Reserves meeting the Long Island 30-Minute Reserves requirement that are less than or equal to the

target level for that requirement, the price on the Long Island 30-Minute Reserves demand curve shall be \$25/MW. For all other quantities, the price on the Long Island 30-Minute Reserves demand curve shall be \$0/MW.

During each real-time interval that the ISO has established a Scarcity Reserve Requirement in the Real-Time Market for which the pricing rules established in Section 15.4.6.1.1(a)(iv) of this Rate Schedule apply, the applicable Operating Reserves demand curve for Long Island 30-Minute Reserves shall be as follows:

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

The ISO will procure additional Operating Reserves to meet each Scarcity Reserve Requirement established by the ISO in the Real-Time Market for which the pricing rules established in Section 15.4.6.1.1(b) of this Rate Schedule apply. The Scarcity Reserve Demand Curve for each real-time interval in which the ISO has established such a Scarcity Reserve

Requirement shall be defined as follows: For quantities of Operating Reserves meeting the Scarcity Reserve Requirement that are less than or equal to the Scarcity Reserve Requirement, the price on the Scarcity Reserve Demand Curve shall be \$500/MW. For all other quantities, the price on the Scarcity Reserve Demand Curve shall be \$0/MW.

In order to respond to operational or reliability problems that arise in real-time, the ISO may procure any Operating Reserve product at a quantity and/or price point different than those specified above. The ISO shall post a notice of any such purchase as soon as reasonably possible and shall report on the reasons for such purchases at the next meeting of its Business Issues Committee. The ISO shall also immediately initiate an investigation to determine whether it is necessary to modify the quantity and price points specified above to avoid future operational or reliability problems. The ISO will consult with its Market Monitoring Unit when it conducts this investigation.

If the ISO determines that it is necessary to modify the quantity and/or price points specified above in order to avoid future operational or reliability problems it may temporarily modify them for a period of up to ninety days. If circumstances reasonably allow, the ISO will consult with its Market Monitoring Unit, the Business Issues Committee, the Commission, and the PSC before implementing any such modification. In all circumstances, the ISO will consult with those entities as soon as reasonably possible after implementing a temporary modification.

Not later than 90 days after the implementation of the Operating Reserves Demand Curves the ISO, in consultation with its Market Advisor, shall conduct an initial review of them in accordance with the ISO Procedures. The scope of the review shall include, but not be limited to, an analysis of whether any Operating Reserve Demand Curve should be adjusted upward or downward in order to optimize the economic efficiency of any, or all, of the ISO Administered

Markets. The ISO and the Market Advisor shall perform additional quarterly reviews, subject to the same scope requirement, during the remainder of the first year that this Section 15.4.7 is in effect. After the first year, the ISO shall perform periodic reviews, subject to the same scope requirement, and the Market Monitoring Unit shall be given the opportunity to review and comment on the ISO's periodic reviews of the Operating Reserve Demand Curves and Scarcity Reserve Demand Curve.

The responsibilities of the Market Monitoring Unit that are addressed in the above section of Rate Schedule 4 to the Services Tariff are also addressed in Section 30.4.6.4.2 of Attachment O.

15.4.8 Self-Supply

Transactions may be entered into to provide for Self-Supply of Operating Reserves. Except as noted in the next paragraph, Customers seeking to Self-Supply Operating Reserves must place the Generator(s) supplying any one of the Operating Reserves under ISO control. The Generator(s) must meet ISO rules for acceptability. The amount that any such Customer will be charged for Operating Reserves will be reduced by the market value of the services provided by the specified Generator(s) as determined in the ISO Services Tariff.

Alternatively, Customers, including LSEs, may enter into Day-Ahead Bilateral financial Transactions, *e.g.*, contracts-for-differences, in order to hedge against price volatility in the Operating Reserves markets.

23.2 Conduct Warranting Mitigation

23.2.1 Definitions

The following definitions are applicable to this Attachment H:

For purposes of Section 23.4.5 of this Attachment H, “**Additional CRIS MW**” shall mean the MW of Capacity for which CRIS was requested for an Examined Facility pursuant to the provisions in ISO OATT Sections 25, 30, or 32 (OATT Attachments S, X, or Z), including either: (i) all, or a portion, of the MW of Capacity of that Examined Facility for which CRIS had not been obtained in prior Class Years through a prior Class Year process or through a transfer completed in accordance with OATT Section 25 (OATT Attachment S); and/or (ii) all, or a portion, of an increase in the Capacity of that Examined Facility. Additional CRIS MW does not include any MW quantity of CRIS that is exempt from an Offer Floor pursuant to Section 23.4.5.7.7(a) or (b), Section 23.4.5.7.8, or an increase of 2 MW or less in an Examined Facility’s MW quantity of CRIS obtained pursuant to Section 30.3.2.6 of Attachment X to the OATT.

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
- iv) all persons or Entities, except 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 Control of Unforced Capacity.

In the foregoing definition, “**control**” means the possession, directly or indirectly, of the power to direct the management or policies of a person or Entity, and shall be rebuttably presumed from an ownership, voting or equivalent interest of ten percent or more.

Catastrophic Failure: shall mean a Forced Outage initially suffered by a Generator which would have reasonably required a repair time of at least 270 days, from the date of the event resulting in the Forced Outage, had it, or a comparable Forced Outage been suffered at a generating facility that is reasonably the same as or similar to the Generator’s, the owner of which is intending to return it to service. Repair time includes the reasonable number of days for initial clean up, safety inspections, engineering assessment; damage assessment, cost estimates; site prep and clean up, equipment orders, and actual repair, provided the foregoing are necessitated by the Catastrophic Failure. The determination that a Generator has suffered a

Catastrophic Failure shall be based on a technical/engineering evaluation, shall be made by the ISO, and may be made at any time following the event that caused the Forced Outage provided that adequate information is provided to the ISO to support such determination.

“Class Year Study” means a Class Year Interconnection Facilities Study as that term is defined in OATT Section 25 (OATT Attachment S).

“Cleared UCAP” means the amount of MW (rounded down to the nearest tenth of a MW) that had been subject to an Offer Floor but has cleared in accordance with Section 23.4.5.7.

“Commenced Construction” shall mean (a) all of the following site preparation work is completed: ingress and egress routes exist; the site on which the project will be located is cleared and graded; there is power service to the site; footings are prepared; and foundations have been poured consistent with purchased equipment specifications and project design; or (b) the following financial commitments have been made: (i) (A) an engineering, procurement, and construction contract (“EPC”) has been executed by all parties and is effective; or (B) contracts (collectively, “EPC Equivalents”) for all of the following have been executed by all parties and is effective: (1) project engineering, (2) procurement of all major equipment, and (3) construction of the project, and (ii) the cumulative payments made by the developer under the EPC or EPC Equivalents to the counterparties to those respective agreements is equal to at least thirty (30) percent of the total costs of the EPC or EPC Equivalents.

“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 UCAP from an RMR Generator.

For purposes of Section 23.4.5.7 **“CRIS MW”** shall mean the MW of Capacity for which CRIS was assigned to a Generator or UDR project pursuant to ISO OATT Sections 25, 30, or 32 (OATT Attachments S, X, or Z).

“Developer” shall have the meaning specified in the ISO’s Open Access Transmission Tariff.

“Electric Facility” shall mean a Generator or an electric transmission facility.

For purposes of Section 23.4.5 of this Attachment H, **“Entity”** shall mean a corporation, partnership, limited liability corporation or partnership, firm, joint venture, association, joint-stock company, trust, unincorporated organization or other form of legal or juridical organization or entity.

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.

For purposes of Section 23.4.5 of this Attachment H, **“Going-Forward Costs”** shall mean: either (a) the costs, including but not limited to mandatory capital expenditures necessary to comply with federal or state environmental, safety or reliability requirements that must be met in order to supply Installed Capacity, net of anticipated energy and ancillary services revenues, as determined by the ISO as specified in Section 23.4.5.3, for each of the following instances, as applicable, of supplying Installed Capacity that could be avoided if an Installed Capacity Supplier otherwise capable of supplying Installed Capacity were either (1) to cease supplying Installed Capacity and Energy for a period of one year or more while retaining the ability to re-enter such markets, or (2) to retire permanently from supplying Installed Capacity and Energy; or (b) the opportunity costs of foregone sales outside of a Mitigated Capacity Zone, net of costs that would have been incurred as a result of the foregone sale if it had taken place.

For purposes of Section 23.4.5 of this Attachment H, **“Indicative Mitigation Net CONE”** shall mean the capacity price calculated by the NYISO for informational purposes only if there is not an effective ICAP Demand Curve and the Commission (i) has accepted an ICAP Demand Curve for the Mitigated Capacity Zone that will become effective when the Mitigated Capacity Zone is first effective, in which case, the Indicative Mitigation Net CONE shall be the capacity price on such ICAP Demand Curve for the Mitigated Capacity Zone corresponding to the average amount of excess capacity above the Indicative NCZ Locational Minimum Installed Capacity Requirement, as applicable, expressed as a percentage of that requirement that formed the basis for the ICAP Demand Curve accepted by the Commission; or, (ii) has not accepted an ICAP Demand Curve for the Mitigated Capacity Zone, but the ISO has filed an ICAP Demand Curve for the Mitigated Capacity Zone pursuant to Services Tariff Section 5.14.1.2.11, 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 Period” shall have the meaning specified in Section 25 (Attachment S) of the ISO’s Open Access Transmission Tariff.

“Interconnection Customer” shall have the meaning specified in Section 32 (Attachment Z) of the ISO’s Open Access Transmission Tariff.

“Interconnection Facilities Study Agreement” shall have the meaning specified in Section 30 (Attachment X) of the ISO’s Open Access Transmission Tariff.

“Market Monitoring Unit” shall have the same meaning in these Mitigation Measures as it has in Attachment O.

“Market Party” shall mean any person or entity that is, or for purposes of the determinations to be made pursuant to Section 23.4.5.7 of this Attachment H proposes or plans a project that would be, a buyer 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, 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.

“**NCZ Examined Project**” shall mean any Generator or UDR project that is not exempt pursuant to 23.4.5.7.8 and either (i) is in a Class Year on the date the Commission accepts the first ICAP Demand Curve to apply to a Mitigated Capacity Zone or (ii) meets the criteria specified in 23.4.5.7.3(II). An NCZ Examined Project may be at any phase of development or in operation or an Installed Capacity Supplier.

For purposes of Section 23.4.5 of this Attachment H, “**Net CONE**” shall mean the localized levelized embedded costs of a peaking unit in a Mitigated Capacity Zone, net of the likely projected annual Energy and Ancillary Services revenues of such unit, as determined in connection with establishing the Demand Curve for a Mitigated Capacity Zone pursuant to Section 5.14.1.2 of the Services Tariff, or as escalated as specified in Section 23.4.5.7 of Attachment H.

“**New Capacity**” shall mean a new Generator, a substantial addition to the capacity of an existing Generator, or the reactivation of all or a portion of a Generator that has been out of service for five years or more that commences commercial service after the effective date of this definition.

For purposes of Section 23.4.5 of this Attachment H, “**Offer Floor**” for a Mitigated Capacity Zone Installed Capacity Supplier that is not a Special Case Resource shall mean the lesser of (i) a numerical value equal to 75% of the Mitigation Net CONE translated into a seasonally adjusted monthly UCAP value (“Mitigation Net CONE Offer Floor”), or (ii) the numerical value that is the first year value of the Unit Net CONE determined as specified in Section 23.4.5.7, translated into a seasonally adjusted monthly UCAP value using an appropriate class outage rate, (“Unit Net CONE Offer Floor”). The Offer Floor for a Mitigated Capacity Zone Installed Capacity Supplier that is a Special Case Resource shall mean a numerical value determined as specified in Section 23.4.5.7.5. The Offer Floor for Additional CRIS MW shall mean a numerical value determined as specified in Section 23.4.5.7.6.

“**Owner**” shall have the meaning specified in Section 31.1.1 of the ISO’s Open Access Transmission Tariff.

For purposes of Section 23.4.5 of this Attachment H, “**Pivotal Supplier**” shall mean (i) for the New York City Locality, a Market Party that, together with any of its Affiliated Entities, (a) Controls 500 MW or more of Unforced Capacity, and (b) Controls Unforced Capacity some portion of which is necessary to meet the New York City Locality Locational Minimum Installed Capacity Requirement in an ICAP Spot Market Auction; (ii) for the G-J Locality, a Market Party that, together with any of its Affiliated Entities, (a) Controls 650 MW or more of Unforced

Capacity; and (b) Controls Unforced Capacity some portion of which is necessary to meet the G-J Locality Locational Minimum Installed Capacity Requirement in an ICAP Spot Market Auction; and (iii) for each Mitigated Capacity Zone except the New York City Locality and the G-J Locality, if any, a Market Party that Controls at least the quantity of MW of Unforced Capacity specified for the Mitigated Capacity Zone and accepted by the Commission.

“Project Cost Allocation” shall have the meaning specified in Section 25 (Attachment S) of the ISO’s Open Access Transmission Tariff.

For purposes of Section 23.4.5 of this Attachment H, **“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 Section 25 (Attachment S) of the ISO’s Open Access Transmission Tariff.

“Subsequent Decision Period” shall have the meaning specified in Section 25 (Attachment S) of the ISO’s Open Access Transmission Tariff.

For purposes of Section 23.4.5 of this Attachment H, **“Surplus Capacity”** shall mean the amount of Installed Capacity, in MW, available in a Mitigated Capacity Zone in excess of the Locational Minimum Installed Capacity Requirement for such Mitigated Capacity Zone.

“Total Evaluated CRIS MW” shall mean the Additional CRIS MW requested plus either (i) if the Installed Capacity Supplier previously received an exemption under Sections 23.4.5.7.2(b), 23.4.5.7.6(b), 23.4.5.7.7 or 23.4.5.7.8, all prior Additional CRIS MW since the facility was last exempted under Sections 23.4.5.7.2(b), 23.4.5.7.6(b), or 23.4.5.7.8, or (ii) for all other Installed Capacity Suppliers, all MW of Capacity for which an Examined Facility obtained CRIS pursuant to the provisions in ISO OATT Sections 25, 30, or 32 (OATT Attachments S, X, or Z).

For purposes of Section 23.4.5 of this Attachment H, **“UCAP Offer Reference Level”** shall mean a dollar value equal to the projected clearing price for each ICAP Spot Market Auction determined by the ISO on the basis of the applicable ICAP Demand Curve and the total quantity of Unforced Capacity from all Installed Capacity Suppliers in a Mitigated Capacity Zone for the period covered by the applicable ICAP Spot Market Auction.

For purposes of Section 23.4.5 of this Attachment H, **“Unit Net CONE”** shall mean localized levelized embedded costs of a specified Installed Capacity Supplier, including interconnection costs, and for an Installed Capacity Supplier located outside a Mitigated Capacity Zone including embedded costs of transmission service, in either case net of likely projected annual Energy and Ancillary Services revenues, and revenues associated with other energy products (such as energy services and renewable energy credits), as determined by the ISO, translated into a seasonally adjusted monthly UCAP value using an appropriate class outage rate. The Unit Net CONE of an Installed Capacity Supplier that has functions beyond the generation or transmission of power shall include only the embedded costs allocated to the production and transmission of power, and shall not net the revenues from functions other than the generation or transmission of power.

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; (iii); making an unjustifiable change to one or more operating parameters of a Generator that reduces its ability to provide Energy or Ancillary Services or (iv) operating a Generator in real-time at a lower output level than the Generator would have been expected to produce had the Generator followed the ISO's dispatch instructions, in a manner that is not attributable to the Generator's verifiable physical operating capabilities and that would not be in the economic interest of the Market Party or its Affiliates in the absence of market power.

For purposes of this Section and Section 23.4.3.2, the term "unjustifiable change" shall mean a change in an Electric Facility's operating parameters that is: (a) not attributable to the 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.

23.2.4.1.3 Uneconomic production from an Electric Facility, that is, increasing the output of an Electric Facility to levels that would otherwise be uneconomic in order to cause, and obtain benefits from, a transmission constraint.

23.2.4.2 Mitigation Measures may also be imposed, subject to FERC's approval, to mitigate the market effects of a rule, standard, procedure or design feature of an ISO Administered Market that allows a Market Party or its Affiliate to manipulate market prices or otherwise impair the efficient operation of that market, pending the revision of such rule, standard, procedure or design feature to preclude such manipulation of prices or impairment of efficiency.

23.2.4.3 Taking advantage of opportunities to sell at a higher price or buy at a lower price in a market other than an ISO Administered Market shall not be deemed a form of withholding or otherwise inconsistent with competitive conduct.

23.2.4.4 The ISO and the Market Monitoring Unit shall monitor the ISO Administered Markets for other categories of conduct, whether by a single firm or by multiple firms acting in concert, that have material effects on prices or guarantee payments in an ISO Administered Market. The ISO shall: (i) seek to amend the foregoing list as may be appropriate, in accordance with the procedures and requirements for amending the Plan, to include any such conduct that would

substantially distort or impair the competitiveness of any of the ISO Administered Markets; and (ii) seek such other authorization to mitigate the effects of such conduct from the FERC as may be appropriate. The responsibilities of the Market Monitoring Unit that are addressed in this section of the Mitigation Measures are also addressed in Section 30.4.6.2.2 of Attachment O.

23.4.5 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 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 is a Pivotal Supplier is located of Mitigated UCAP (either of the foregoing being referred to as “External Sale UCAP”) 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 be deemed to have been physically withheld on the basis of a comparison of the net revenues from UCAP sales that would have been earned by the sale in a Mitigated Capacity Zone of External Sale UCAP. The comparison shall be made for the period for which Installed 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 Mitigated UCAP was

exported or sold. External Sale ICAP 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 (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.

(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 is not offered or sold as specified above, the Responsible Market Party for such Installed Capacity Supplier 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 and (B) the total of (1) the amount of Mitigated 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. If the failure to offer was associated with the same period as the sale of External Sale UCAP, 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 Installed Capacity Supplier shall be required to pay to the ISO an amount equal to 1.5 times the lesser of (A) 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 inclusion of the External Sale UCAP in those auctions, or (B) the difference between such average price and the clearing price in the External Reconfiguration Market for the relevant Comparison Period, times the total of (1) the amount of Mitigated 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. 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.

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 External UCAP Sales that would exceed the net revenues that would have been realized from sale of the External UCAP Sales capacity 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.

(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.

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 except the G-J Locality, the presumption of Control of Unforced Capacity can be rebutted by: (1) the sale of Unforced Capacity in a Capability Period Auction or a Monthly Auction, or (2) 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. For purposes of determining if a Responsible Market Party is a Pivotal Supplier in the G-J Locality, 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.

23.4.5.6 Audit, Review, and Penalties for Physical Withholding to Increase Market-Clearing Prices

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 from a Mitigated Capacity Zone Unforced Capacity market, or to derate 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. Such an audit or review shall assess whether the proposal or decision has a legitimate economic justification or is based on an effort to withhold Installed Capacity physically in order to affect prices. 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.

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 Party 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 Party 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 Party'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.

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.

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 Party has Commenced Repair of the Generator, or the Generator is determined by the ISO to have had a Catastrophic Failure, the Market Party 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.

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 Party, a determination that the Market Party 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 Party 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 Party, 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 Party 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 Party 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 Party 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.

23.4.5.7 Unless exempt as specified below, offers to supply Unforced Capacity from a Mitigated Capacity Zone Installed Capacity Supplier: (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), the Offer Floor shall apply to offers for Unforced Capacity from the Installed Capacity Supplier, if it is not a Special Case Resource, 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. Offer Floors shall cease to apply to that portion of a resource'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"). Offer Floors shall be adjusted annually using the inflation rate component of the escalation factor of the relevant effective ICAP Demand Curves that have been accepted by the Commission.

23.4.5.7.1 Unforced Capacity from an Installed Capacity Supplier that is subject to an Offer Floor 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 Installed Capacity Supplier, in a Mitigated Capacity Zone for which the Commission has accepted an ICAP Demand Curve, shall be exempt from an Offer Floor if: (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 Summer Capability Period commencing three years from the start of the year of the Class Year (the "Starting Capability Period") is projected by the ISO to be higher, with the inclusion of the Installed Capacity Supplier, than (y) the

numerical value equal to 75 percent of the Mitigation Net CONE that would be applicable to such supplier 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 six Capability Periods beginning with the Starting Capability Period is projected by the ISO to be higher, with the inclusion of the Installed Capacity Supplier, than the reasonably anticipated Unit Net CONE of the Installed Capacity Supplier, or (c) it has been determined to be exempt pursuant to Section 23.4.5.7.9 (the “Competitive Entry Exemption”). For purposes of the determinations pursuant to (a) and (b) of this section, the ISO shall identify Unit Net CONE and the price on the ICAP Demand Curve projected for a future Mitigation Study Period consistent with Sections 23.4.5.7.3.2 or 23.4.5.7.4, as appropriate, for each Examined Facility promptly after it (i) has accepted its SDU Project Cost Allocation 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 (OATT Attachment S) (for purposes of Section 23.4, a project that “remains a member of a completed Class Year”). The first year value of an Examined Facility’s Unit Net CONE will be calculated pursuant to Section 23.4.5.7, Section 23.4.5.7.2.4, or 23.4.5.7.3.2, will be established 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. Any determination received pursuant to this Section 23.4.5.7.2, Section 23.4.5.7.6. or 23.4.5.7.7 shall not become final for the relevant Examined Facility unless the Examined Facility accepts its SDU

Project Cost Allocation and deliverable MW, if any, from the Final Decision Round, and posted any associated security pursuant to OATT Section 25, and remains a member of the completed Class Year. The Unit Net CONE or exemption determination pursuant to this Section shall be final on the date the ISO issues a notice to stakeholders that the Class Year decisional process has been completed.

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 is in a completed Class Year 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 5.14.1.2.11. 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 completed at the time the Commission accepts the Demand Curve, or (ii) has not been removed from the Class Year Deliverability Study if the Class Year 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 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.

The ISO shall compute the reasonably anticipated ICAP Spot Market Auction forecast price based on Expected Retirements (as defined in subsection 23.4.5.7.2.3.1), plus each NCZ Examined Project.

23.4.5.7.2.3.1 Expected Retirements shall be determined based on any Generator that provided written notice to the New York State Public Service Commission that it intends to retire, plus any UDR projects, or any Generator 2 MW or less that provided written notice to the ISO that it intends to retire.

23.4.5.7.2.3.2 The Load forecast shall be based on data used to develop the Indicative Locational Minimum Installed Capacity Requirement, and Special Case Resources based on data for the Mitigated Capacity Zone that is part of the

Special Case Resource data set forth in the most-recently published Load and Capacity Data (Gold Book).

23.4.5.7.2.4 The ISO shall post on its website the inputs of the reasonably anticipated ICAP Spot Market Auction forecast prices determined in accordance with 23.4.5.7.2.3 (except for the posting of an input which would disclose Confidential Information), the Expected Retirements, and the NCZ Examined Projects, before the exemption or Offer Floor determination under this Section.

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.

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 or Offer Floor exemption determination or Indicative Buyer-Side Mitigation Exemption Determination 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 30.4.6.2.12 of Attachment O.

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) 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” (collectively “Examined Facilities”) which term 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 that requested CRIS, or that requested an evaluation of the transfer of CRIS rights from another location, in the Class Year Facilities Study commencing in the calendar year in which the Class Year Facility Study determination is being made (the Capability Periods of expected entry as further described below in this Section, the “Mitigation Study Period”) and (II) each (i) existing Generator that did not have CRIS rights, and (ii) proposed new Generator and proposed new UDR project, provided such Generator under Subsection (i) or (ii) is an expected recipient of transferred CRIS rights at the same location regarding which the ISO has been notified by the transferor or the transferee of a transfer pursuant to

OATT Attachment S Section 25.9.4 that will be effective on a date within the Mitigation Study Period.

23.4.5.7.3.1 The commercial operation date to be used by the ISO solely for purposes of identifying the Examined Facilities will be determined by the ISO at the time of the Class Year Study as the date most-recently (A) identified by the project to the ISO in the Interconnection Facilities Study process or (B) reflected in the Interconnection Queue, or if neither of the foregoing is applicable, then the date identified by the project to the Transmission Owner to which it has proposed interconnecting.

23.4.5.7.3.2 The ISO shall compute the reasonably anticipated ICAP Spot Market Auction forecast price for any Mitigated Capacity Zone based on Expected Retirements (as defined in this subsection 23.4.5.7.3.2), plus each Examined Facility in 23.4.5.7.3 (I) or (II).

Expected Retirements shall be determined based on any Generator that provided written notice to the New York State Public Service Commission that it intends to retire, plus any UDR project or Generator 2 MW or less that provided written notice to the ISO that it intends to retire.

The load forecast and Special Case Resources shall be as set forth in the most-recently published Load and Capacity Data (Gold Book).

Before the commencement of the Initial Decision Period for the Class Year, the ISO shall post on its website the inputs of the reasonably anticipated ICAP Spot Market Auction forecast prices determined in accordance with 23.4.5.7.3.2, the Expected Retirements, and the Examined Facilities, before the Initial Project Cost

Allocation, subject to any restrictions on the disclosure of Confidential Information or Critical Energy Infrastructure Information.

When the ISO is evaluating more than one Examined Facility concurrently, the ISO shall recognize in its computation of the anticipated ICAP Spot Market Auction forecast price that Generators or UDR project 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.

23.4.5.7.3.3 All developers, 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 but that only has ERIS rights after the Project Cost Allocation process is complete, 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 in which the Generator or UDR project requests CRIS. The ISO shall determine the reasonably anticipated Unit Net CONE less the costs to be determined in the Project Cost Allocation or Revised Project Cost Allocation, as applicable, prior to the commencement of the Initial Decision Period Class Year, and shall provide to the Examined Facility the ISO's initial determination of an exemption or the Offer Floor. On or before the three (3) days prior to the ISO's issuance of the Revised Project Cost Allocation, the ISO will revise its forecast of ICAP Spot Market

Auction prices for the Capability Periods in the Mitigation Study Period based on the Examined Facilities that remain in the Class Year for CRIS and the Examined Facilities that meet 23.4.5.7.3 (II). When evaluating Examined Capacity 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 ISO shall provide to each project its revised price forecast and a revised initial determination for a Subsequent Decision Period no later than the ISO's issuance of a Revised Project Cost Allocation. If a project remains a member of a completed Class Year, the ISO shall inform the project of the final determination of the Offer Floor or whether the Offer Floor exemption specified above in this Section is applicable as soon as practicable after the date the ISO issues a notice to stakeholders that the Class Year decisional process has been completed, in accordance with methods and procedures specified in ISO Procedures. 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.

23.4.5.7.3.4 If an Examined Facility under the criteria in 23.4.5.7.3 (II) has not provided written notice to the ISO on or before the date specified by the ISO, 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 in Section 23.4.5.7.3 (I) and either (a) enters a new Class Year for CRIS or (b) intends to receive transferred CRIS rights at the same location. An Examined Facility under the criteria in 23.4.5.7.3 (II) that did receive CRIS rights will be bound by the determination rendered and will not be reevaluated. An Examined Facility under the criteria that had been set forth in 23.4.5.7.3 (III) prior to May 19, 2016 will not be reevaluated.

23.4.5.7.3.6 If an Installed Capacity Supplier demonstrates to the reasonable satisfaction of the ISO that the value equal to the first of the three year values in the Mitigation Study Period that comprise its Unit Net CONE is less than any Offer Floor that would otherwise be applicable to the Installed Capacity Supplier, then its Offer Floor shall be reduced to a numerical value equal to the first year of its Unit Net CONE.

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 inflation rate component identified in Section 23.4.5.7. 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 component 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 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, 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 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 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 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 30.4.6.2.12 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 UDR project that is an Examined Facility or an NCZ Examined Project withdraws from a Class Year and then enters another Class Year (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 (A) the Unit Net CONE projected for a Mitigation Study Period using: (i) the inflation rate component of the escalation factor of the relevant ICAP Demand Curves for any year for which there are accepted ICAP Demand Curves, and (ii) the inflation rate component of the escalation factor of the last year of accepted relevant ICAP Demand Curves if relevant ICAP Demand Curves do not apply to the year; and (B) the price on the ICAP Demand Curve projected for a Mitigation Study Period using (i) the escalation factor of the relevant ICAP Demand Curves for any year for which there are accepted ICAP Demand Curves; and (ii) the escalation factor of the last year of accepted ICAP Demand Curves if relevant ICAP Demand Curves do not apply to the year. For purposes of Section 23.4.5.7.2(a), the ISO shall use the escalation factor of the relevant ICAP Demand Curves.

23.4.5.7.5 A Mitigated Capacity Zone Installed Capacity Supplier that is a Special Case Resource shall be subject to an Offer Floor beginning with the month of its initial offer to supply Installed Capacity, and until its offers of Installed Capacity have been accepted in the ICAP Spot Market Auction at a price at or above its Offer Floor for a total of twelve, not necessarily consecutive, months. A Special Case Resource shall be exempt from the Offer Floor if (a) it is located in a Mitigated Capacity Zone except New York City and is enrolled as a Special Case Resource with the ISO for any month within the Capability Year that includes March 31 in an ICAP Demand Curve Reset Filing Year in which the ISO proposes a New Capacity Zone that includes the location of the Special Case

Resource, or (b) the ISO projects that the ICAP Spot Market Auction price will exceed the Special Case Resource's Offer Floor for the first twelve months that the Special Case Resource reasonably anticipated to offer to supply UCAP. If a Responsible Interface Party fails to provide Special Case Resource data that the ISO needs to conduct the calculations described in the two preceding sentences by the deadline established in ISO Procedures, the Special Case Resource will cease to be eligible to offer or sell Installed Capacity. The Offer Floor for a Special Case Resource shall be equal to the minimum monthly payment for providing Installed Capacity payable by its Responsible Interface Party, plus the monthly value of any payments or other benefits the Special Case Resource receives from a third party for providing Installed Capacity, or that is received by the Responsible Interface Party for the provision of Installed Capacity by the Special Case Resource. The Offer Floor calculation for a Special Case Resource located in New York City shall include any payment or the value of other benefits that are awarded for offering or supplying Mitigated Capacity Zone Capacity unless such payment or the value of other benefits is ruled exempt by Commission order in response to a request for exemption filed under section 206 of the Federal Power Act by New York State or a government instrumentality of New York State. The Offer Floor calculation for a Special Case Resource located in a Mitigated Capacity Zone except New York City shall include any payment or the value of other benefits that are awarded for offering or supplying Mitigated Capacity Zone Capacity, except for payments or the value of other benefits provided under programs administered or approved by New York State or a government

instrumentality of New York State. Offers by a Responsible Interface Party at a PTID shall be not lower than the highest Offer Floor applicable to a Special Case Resource providing Installed Capacity at that PTID. Such offers may comprise a set of points for which prices may vary with the quantity offered. If this set includes megawatts from a Special Case Resource(s) with an Offer Floor, then at least the quantity of megawatts in the offer associated with each Special Case Resource must be offered at or above the Special Case Resource's Offer Floor. Offers by a Responsible Interface Party shall be subject to audit to determine whether they conformed to the foregoing Offer Floor requirements. If a Responsible Interface Party together with its Affiliated Entities submits one or more offers below the applicable Offer Floor, and such offer or offers cause or contribute to a decrease in UCAP prices in the Mitigated Capacity Zone of 5 percent or more, provided such decrease is at least \$.50/kilowatt-month, the Responsible Interface Party shall be required to pay to the ISO an amount equal to 1.5 times the difference between the Market-Clearing Price for the Mitigated Capacity Zone in the ICAP Spot Auction for which the offers below the Offer Floor were submitted with and without such offers being set to the Offer Floor, times the total amount of UCAP sold by the Responsible Interface Party and its Affiliated Entities in such ICAP Spot Auction. If an offer is submitted below the applicable Offer Floor, the ISO will notify the Responsible Market Party and the notification will identify the offer, the Special Case Resource, the price impact, and the penalty amount. The ISO will provide the notice reasonably in advance of imposing such penalty. The ISO shall distribute any amounts recovered in

accordance with the foregoing provisions among the entities, other than the entity subject to the foregoing payment requirement, supplying Installed Capacity in regions affected by one or more offers below an applicable Offer Floor in accordance with ISO Procedures.

23.4.5.7.6 Exemptions for Additional CRIS MW: All requests for Additional CRIS MW located in a Mitigated Capacity Zone, in a Class Year or through a transfer, shall be evaluated for a buyer-side mitigation exemption or Offer Floor in accordance with this Section. Additional CRIS MW obtained in a Class Year 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 Class Year (the “Starting Capability Period”) is projected by the ISO, with the inclusion of the Additional CRIS MW, 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)); or (b) if the price that is equal to the average of the ICAP Spot Market Auction prices in the six Capability Periods beginning with the Starting Capability Period is projected by the ISO, with the inclusion of the Installed Capacity Supplier’s Additional CRIS MW, 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.

23.4.5.7.6.1 For Additional CRIS MW that have an exemption or Offer Floor

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 most recent prior determination concluded that the 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, 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 Sections 23.4.5.7.2.4 or 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 inflation rate component of the escalation factor of the most currently accepted ICAP Demand Curves 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. If the Examined Facility is an Intermittent Power Resource

or Limited Control Run-of-River Hydro Resource, the ISO shall apply a 5-year average derating factor based on ISO data to establish the EFORD to be utilized in the calculation pursuant to this paragraph. 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 Sections 30.4.6.2.12 and 30.10.4 of Attachment O to this Services Tariff.

23.4.5.7.7 (a) An In-City Installed Capacity Supplier that is not a Special Case Resource shall be exempt from an Offer Floor if it was an existing facility on or before March 7, 2008. (b) 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

OATT Attachment S (“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 to the OATT. If the Generator or UDR project subsequently received CRIS 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 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 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 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 OATT Attachment S (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 subject to a deliverability requirement (and therefore, is not in a Class Year 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 30.4.6.2.12 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

23.4.5.7.9.1.1 A proposed new Generator or UDR project that becomes a member of a Class Year after Class Year 2012 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 Generator or UDR project meets each of the following requirements: (a) does not have, and at no time before the Generator first produces or the 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 Transmission Owner, a 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, (collectively “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”) that: (a) directly relates to the planning, siting, interconnection, operation, or construction of the Generator or UDR project that is the subject of the request for the Competitive Entry Exemption; (b) is for the energy or capacity produced by or delivered from or by the Generator or UDR project, including an agreement for rights to schedule or use a UDR; or (c) provides services, financial support, or tangible goods to a Generator or UDR project. For purposes of Section 23.4.5.7.9, an indirect “non-qualifying contractual relationship” is any contract between the Generator or UDR project 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, the recital, purpose, or subject of which includes, or has the effect of including, this Generator or UDR project.

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 X of the New York State Public Service Law or orders issued pursuant to Articles VII or X); (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. 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 (viii) of this Section a non-qualifying contractual relationship.

23.4.5.7.9.1.4 The ISO shall determine whether a Generator or UDR project is eligible for a Competitive Entry Exemption based on its review of the certifications required by Section 23.4.5.7.9.2, 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 30.4.6.2.12 of Attachment O.

23.4.5.7.9.2 Certifications and Acknowledgements

23.4.5.7.9.2.1 A Generator or UDR project 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 form executed by a duly authorized officer:

CERTIFICATION AND ACKNOWLEDGMENT

I [NAME & TITLE] hereby certify on behalf of myself, [NAME OF PROJECT], 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 [EXAMINED FACILITY], New York Independent System Operator, Inc.'s ("NYISO") Interconnection 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/ACKNOWLEDGE THE PRIOR SUBMISSION IN THIS CLASS YEAR BY] the Developer 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 for the Project 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 with Non-Qualifying Entry Sponsors on Schedule 1 to this Certification.

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) – (viii) of the Services Tariff.
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 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) of the Services Tariff, and (b) all agreements that would not constitute a non-qualifying contractual relationship are on Schedule 1 to this certification.
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 Project 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 DEVELOPER] 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 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, 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 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 date of the revocation pursuant to Section 23.4.5.7.9.5.3 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: _____

**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 and each time the ISO requests a resubmittal of a certification, until the Generator's or UDR project's Entry Date.

23.4.5.7.9.2.5 The Generator or UDR project must notify the ISO if information in a certification ceases to be true, promptly upon such occurrence or learning information previously provided was not true.

23.4.5.7.9.2.6 Failure to provide, without prior notification, 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 notification is provided to the ISO, within 2 business days of receipt of a request from the ISO for information or cooperation, that the information or cooperation requested will not be provided, such refusal will not be considered a false, misleading, or inaccurate submission for purposes of Section 23.4.5.7.9.5 as long as the information is provided by the earlier of a mutually agreed upon deadline or thirty (30) calendar days. A refusal to provide information or any other failure to provide information by that deadline will make the Generator or UDR project requesting a Competitive Entry Exemption ineligible for such exemption, and such Generator or UDR project shall be subject to the Mitigation Net CONE Offer Floor (such value 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.)

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 and updated certifications at any time prior to a Generator's or UDR project's Entry Date. A Generator or UDR project that is granted an 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 of the Services Tariff, updated as appropriate, upon its Entry Date.

23.4.5.7.9.3.2 Requests for Competitive Entry Exemptions for Generators or UDR projects in Class Years subsequent to Class Year 2012 must be received by the ISO no later than the deadline by which a facility must notify the ISO of its election to enter the Class Year, such date as set forth in Section 25.5.9 OATT Attachment S. A Generator or UDR project that remains a member of a 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 a Generator or UDR project is exempt, subject to any required further submissions of information, or not exempt under the Competitive Entry Exemption, prior to the Initial Decision Period within which a Developer 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 Developer.

23.4.5.7.9.3.3 A Generator or UDR project 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 2 business days of doing so. A Generator or UDR project seeking to withdraw its request pursuant to this section 23.4.5.7.9.3.3 shall be subject to the Mitigation Net CONE Offer Floor (such value calculated based on its 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,) 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 Generator or UDR project that requests a Competitive Entry Exemption that becomes a member of the Class Year, promptly after 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 and deposit.) 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 Sections 30.4.6.2.12 and 30.10.4 of Attachment O to the 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 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 Generator or UDR project that its Competitive Entry Exemption may be revoked, and provided 30 days written notice has been given to the Generator or UDR project (such notice to the extent practicable,) the ISO may revoke the Competitive Entry Exemption and apply 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.) 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 Generator or UDR project 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.

23.4.5.7.10 The ISO shall post on its website the identity of the project 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 Sections 30.4.6.2.12 and 30.10.4 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, and if the Offer Floor is higher than the applicable offer cap shall submit offers not lower than the applicable Offer Floor.

23.4.5.7.12 For an RMR Generator that has UCAP subject to an Offer Floor, the UCAP subject to the Offer Floor shall be offered at the higher of the Offer Floor and the RMR UCAP Offer Price.

23.4.5.8 RMR Agreement Capacity Price and Offer Requirements

23.4.5.8.1 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 in the amount of UCAP MW and at the price computed

in accordance with this Section the (“RMR UCAP Offer Price”). The RMR UCAP Offer Price shall be \$0.00/kW-month; unless (a) the ISO’s determination of the need for the RMR Agreement is based in whole or in part on a resource adequacy need, or (b) (i) the ISO identifies pursuant to Section 31.2.11.8.2 of the ISO OATT that there is a Viable and Sufficient transmission or demand response Gap Solution that has an estimated net present value that is distinctly higher than that of any Initiating Generator or Generator that is a Viable and Sufficient Gap Solution for the Reliability Need (*i.e.*, the non-generator Viable and Sufficient Gap Solution has a lower net cost,) to the extent that the RMR Generator is expected to address the Reliability Need; (ii) the ISO determines that the transmission or demand response Gap Solution identified pursuant to Section 31.2.11.8.2 of the ISO OATT can be available for a period during the term of the RMR Agreement; and (iii) absent the circumstances described in Section 23.4.5.8.2.1. In the event that the conditions under either Subsection (a) or (b) of this Section 23.4.5.8.2 are met, the RMR UCAP Offer Price shall be the value computed by the ISO for that RMR Generator that is the RMR Avoidable Costs, net of likely projected annual Energy and Ancillary Services revenues, translated into a seasonally adjusted \$/kW-month UCAP value beginning with the month following the in service date of the distinctly higher net present value transmission or demand response Gap Solution at the time of the ISO’s determination pursuant to Section 31.2.11.8.2 of the ISO OATT, and lasting until the RMR Agreement terminates.

23.4.5.8.2.1 Circumstances in which 23.4.5.8.2 (b)(ii) would not be met include the ISO's determination that the Viable and Sufficient transmission or demand response Gap Solution would be reasonably delayed; it was not reasonably practicable for such Gap Solution to proceed in order to be available by the date it identified in its response to the ISO's request for Gap Solutions (as modified from time to time,) or it was not able to timely obtain necessary permits, governmental authorizations, or financing.

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 25.7.11.1.1 and 25.7.11.1.2 of Attachment S to the ISO OATT that results in a charge or other a sanction under Section 25.7.11.1.3 of Attachment S 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.

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 Bid(s) to develop reference levels for the affected Generator(s) in the relevant (Day-Ahead or real-time) market for the durations specified in Sections 23.3.1.4.6.8.1, 23.3.1.4.6.8.2, and 23.3.1.4.6.8.3 of the Mitigation Measures. *See* Section 23.3.1.4.6.8 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 and fuel type information, is accurate. Except as set forth in Section 23.3.1.4.6.7 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. 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). 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) 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. Such an audit or review shall assess whether the proposal or decision has a legitimate economic justification or is based on an effort to withhold Installed Capacity physically in order to affect prices. 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 Party 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 Party'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. 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. If, at the time the ISO acquires the necessary data, the Market Party has Commenced Repair of the Generator, or the Generator is determined by the ISO to have had a Catastrophic Failure, the Market Party 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 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. 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, 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.

30.4.6.2.13 RMR Generator Energy and Ancillary Service Market Participation Rules.

In advance of the execution of an RMR Agreement, the ISO, in consultation with the Market Monitoring Unit and the 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 23.6.2.2.

If a possible RMR Generator faces operational constraints the ISO, in consultation with the Market Monitoring Unit and the 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 23.6.2.2.1.

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 Owner. *See* Market Mitigation Measures Section 23.6.2.3.4.

The ISO and the 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 23.6.2.3.5.

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 Section 5.14.1.2.5.

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 Congestion Analysis and Resource Integration Study

Following the Management Committee vote, the draft Congestion Analysis and Resource Integration Study (CARIS), with Business Issues Committee and Management Committee input, will be forwarded to the ISO Board for review and action. Concurrently, the draft CARIS will be provided to the Market Monitoring Unit for its review and consideration. *See* Section 31.3.2.2 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 comment from the Market Monitoring Unit when (i) making determinations under Section 31.2.11.8 of Attachment Y to the OATT, (ii) determining RMR Avoidable Costs, (iii) identifying the non-generation Viable and Sufficient Gap Solution that has an estimated net present value that is distinctly higher than the net present value of any Initiating Generator or Generator that is a Viable and Sufficient Gap Solution (*i.e.*, the non-generation Viable and Sufficient Gap Solution has a lower net cost,) if any, (iv) reviewing Proposed Additional Costs, and (v) determining Substantiated Additional Costs. *See* Section 31.2.11.18.1 of Attachment Y to the ISO OATT.

If the ISO identifies a non-generation Viable and Sufficient Gap Solution with an estimated net present value that is distinctly higher than the estimated net present value of any Initiating Generator or Generator that is a Viable and Sufficient Gap Solution for a Reliability Need (*i.e.*, the non-generation Viable and Sufficient Gap Solution has a lower net cost,) in accordance with Section 31.2.11.8.2, the Market Monitoring Unit shall publish a report. The report shall review the ISO's cost determinations for non-generation Viable and Sufficient Gap Solutions and RMR Avoidable Costs for Initiating Generators and Generators that are Viable and Sufficient Gap Solutions for a Reliability Need to the extent necessary to report on the ISO's identification of the highest net present value of non-generation Viable and Sufficient Gap Solution. *See* Section 31.2.11.18.2 of Attachment Y to the ISO OATT.

Concurrent with the ISO or a Generator filing with the Commission an RMR Agreement pursuant to Sections 31.2.11.11.3, 31.2.11.11.4, or 31.2.11.11.5, 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 Section

31.2.11.10.6 of Attachment Y to the ISO OATT. In the event that cost alone did not provide for a clear delineation between two or more offers, the report shall also review the ISO's consideration the size of the Generators in an effort to minimize impacts to markets. If the RMR Agreement contains RMR 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 31.2.11.18.3 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 G to Attachment Y 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).