

Attachment III

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.

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.

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.

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.

~~**Available Reserves:** For purposes of determining the Real-Time Locational Based Marginal Price in any Real-Time Dispatch interval: the capability of all Suppliers to provide Operating Reserves in that interval and in the relevant location, minus the quantity of Scheduled Operating Reserves in that interval.~~

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 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.

2.5 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.

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 indicates it expects to be able to reach, 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 Generator or Demand Side 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 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).

2.19 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.

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.

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 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.

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 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.

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.

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. 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.

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.

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 ~~applying Real-Time special scarcity pricing rules described in Attachment B~~ 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 ~~applying Real-Time special scarcity pricing rules described in Attachment B~~ 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 — Real-Time Scarcity Pricing Rules Applicable to Regulation Service and Operating Reserves During EDRP and/or SCR Activations~~

~~Under Section 17.1.2.2 of Attachment B to this ISO Services Tariff, the ISO will use special scarcity pricing rules to calculate Real-Time LBMPs during intervals when it has activated the EDRP and/or SCRs in identified Load Zones due to a reliability need. During these intervals, the ISO will also implement special scarcity pricing rules for real-time Regulation Capacity and Operating Reserves. These rules are set forth in Rate Schedule 15.3 and Rate Schedule 15.4 of this ISO Services Tariff.~~

4.4.2.87 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.

15.3 Rate Schedule 3 - Payments for Regulation Service

This Rate Schedule applies to Suppliers that 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 15.3.5.54.1 and to compute a performance charge to apply to real-time Regulation Service providers pursuant to Section 15.3.5.54.2 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. ~~Except when the circumstances described below in Section 15.3.5.2 apply,~~

~~€~~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) ~~provided however, if the marginal Resource selected to provide Regulation Service for the interval is in a Load Zone for which certain scarcity conditions apply but the ISO has not applied the pricing rule described in Section 15.4.6.2.1, the margins on the sale of Energy or Operating Reserves in the Real-Time Market that the marginal Resource would forego if scheduling it to provide additional Regulation Service would lead to it being scheduled to~~

~~provide less Energy or Operating Reserves, would be as calculated by RTD for that interval.~~

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 — Calculation of Real-Time Market Prices for Regulation Capacity During EDRP/SCR Activations~~

~~During any interval in which the ISO is using the scarcity pricing rule to calculate LBMPs under Section 17.1.2.2 of Attachment B to this ISO Services Tariff, and is also using the scarcity pricing rule in Section 15.4.6.2.1 to price Operating Reserves in that interval, the real-time Regulation Capacity Market Price may be recalculated in light of the Regulation Bids of Suppliers and Lost Opportunity Costs of Generators scheduled to provide Regulation Service in real-time.~~

~~Specifically, when the NYISO is using the scarcity pricing rule in Section 15.4.6.2.1 to calculate Operating Reserves prices in an interval, the real-time Regulation Capacity Market Price shall be set to the higher of: (i) the highest total Regulation Capacity Bid and Lost Opportunity Cost of any Regulation Service provider scheduled by RTD; and (ii) the Market Price calculated under Section 15.3.5.1 of this Rate Schedule.~~

15.3.5.32 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 15.3.5.54.1.
- (d) The ISO shall assess a performance charge, pursuant to Section 15.3.5.54.2 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.

15.3.5.43 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.

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

15.3.5.54.1 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 15.3.5.32 shall be reduced to reflect the Supplier's performance using a performance factor developed

pursuant to the following equation:

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

Where:

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

PI_i = the performance index of the Resource for interval i , with a value between 0.0 and 1.0 inclusive, derived from each Supplier's Regulation Service performance, as measured by the performance indices set forth in the ISO Procedures; and

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

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

15.3.5.54.2 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.

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

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

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

- $RTRcap_i$ = is the Regulation Capacity (in MW) offered by the Resource and selected by the ISO in the Real-Time Market in RTD interval i ;
- $RTRinccap_i$ = is the incremental Regulation Capacity (in MW) offered by the Resource and selected by the ISO in the Real-Time Market in the RTD interval i which is in excess of Regulation Capacity offered and selected by the ISO in the Day-Ahead Market for the hour that includes interval i ;
- S_i = is the number of seconds in interval i ; and
- K_{PIi} = is the performance factor for the Resource for interval i as defined in Section 15.3.5.54.1.

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:

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

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:

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

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 ~~\$400~~\$525/MW.

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

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

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

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

Not later than 90 days after the implementation of the Regulation Service Demand Curve the ISO, in consultation with its Advisor, shall conduct an initial review in accordance with the ISO Procedures. The scope of the review shall be upward or downward in order to optimize the economic efficiency of any, or all, the ISO-Administered Markets. The ISO and the Market Advisor shall perform additional quarterly reviews, subject to the same scope requirement, during the remainder of the first year that this Section 15.3.7 is in effect. After the first year, the ISO shall perform periodic reviews, subject to the same scope requirement, and the Market Monitoring Unit shall be given the opportunity to review and comment on the ISO's periodic reviews of the Regulation Service Demand Curve.

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

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

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

15.4 Rate Schedule 4 - Payments for Supplying Operating Reserves

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

15.4.1 General Responsibilities and Requirements

15.4.1.1 ISO Responsibilities

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

The ISO shall define requirements for Spinning Reserve, which may be met only by Suppliers that are eligible, under Section 15.4.1.2 of this Rate Schedule, to provide Spinning Reserve; 10-Minute Reserve, which may be met by Suppliers that are eligible to provide either Spinning Reserve or 10-Minute Non-Synchronized Reserve; and 30-Minute Reserve, which may be met by Suppliers that are eligible to provide any Operating Reserve product. The ISO shall also define locational requirements for Spinning Reserve, 10-Minute Reserve, and 30-Minute Reserve located East of Central-East, in Southeastern New York 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).

15.4.1.2.2 10-Minute Non-Synchronized Reserve:

Off-line Generators that are capable of starting, synchronizing, and increasing their output level within ten (10) minutes and that meet the criteria set forth in the ISO Procedures, and, Demand Side Resources that are capable of reducing their Energy usage within ten (10) minutes and that meet the criteria set forth in the ISO Procedures, shall be eligible, to supply 10-Minute Non-Synchronized Reserve.

15.4.1.2.3 30-Minute Reserve:

(i) Generators 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; (ii) Off-line Generators that are capable of starting, synchronizing, and increasing their output level within thirty (30) minutes and that meet the criteria set forth in the ISO Procedures, and Demand Side Resources

that are capable of reducing their Energy usage within thirty (30) minutes and 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 ~~R~~eserves 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. ~~Except when the circumstances described below in Section 15.4.6.2 apply, e~~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 ~~Calculation of Real-Time Market Clearing Prices for~~ Establishment of Operating Scarcity Reserves 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.

~~During any interval in which the ISO is using scarcity pricing to calculate LBMPs under Section 17.1.2.2 of Attachment B to this ISO Services Tariff, the ISO shall also determine whether scarcity conditions for Operating Reserves exist, as defined below and shall apply the appropriate scarcity pricing rule for Operating Reserves as indicated. When scarcity conditions for pricing Operating Reserves exist, as described below the real time market clearing prices for some Operating Reserves products may be recalculated in light of the Lost Opportunity Costs of Resources that are scheduled to provide Spinning Reserves and synchronized 30 Minute Reserves in the manner described below. The ISO shall also consider the Lost Opportunity Costs of Resources providing lower quality Operating Reserves to ensure that the requirements of Section 15.4.4.3 of this Rate Schedule are not violated.~~

~~The ISO shall use the scarcity pricing rule described in Section 15.4.6.2.1. below, for each interval in which EDRP/SCR Resources have been called in response to a reliability need in any Load Zone in the NYCA, and the NYISO uses the scarcity pricing rule described in Section 17.1.2.2 of this Services Tariff in the interval, and the aggregate of Available Reserves in all Load Zone(s) in the NYCA are less than the number of EDRP/SCR MW called for that event.~~

~~If the NYISO does not use the scarcity pricing rule described in Section 15.4.6.2.1 in an interval in which EDRP/SCR Resources have been called only in a Load Zone or Load Zones East of Central East, the ISO shall use the scarcity pricing rule described in Section 15.4.6.2.2, below, for each interval in which EDRP/SCR Resources have been called in response to a reliability need only in a Load Zone or Load Zones East of Central East, and the NYISO uses the scarcity pricing rule described in Section 17.1.2.2 of this Services Tariff in the interval, and the aggregate of Available Reserves in all Load Zone(s) East of Central East are less than the number of EDRP/SCR MW called for that event.~~

~~If the NYISO does not use the scarcity pricing rule described in Section 15.4.6.2.1 or 15.4.6.2.2 in an interval in which EDRP/SCR Resources have been called only in a Load Zone or Load Zones in Southeastern New York, the ISO shall use the scarcity pricing rule described in Section 15.4.6.2.3, below, for each interval in which EDRP/SCR Resources have been called in response to a reliability need only in a Load Zone or Load Zones in Southeastern New York, and the NYISO uses the scarcity pricing rule described in Section 17.1.2.2 of this Services Tariff in the interval, and the aggregate of Available Reserves in all Load Zone(s) in Southeastern New York are less than the number of EDRP/SCR MW called for that event.~~

~~If no scarcity pricing rule is indicated under either test described above, the NYISO shall apply the pricing rules contained in Section 14.4.6.1 for each Operating Reserves product.~~

~~15.4.6.2.1 Pricing of Operating Reserves During Intervals of Statewide Scarcity~~

~~The Eastern Spinning Reserve market clearing price shall be the higher of: (i) the highest Lost Opportunity Cost of any provider of Spinning Reserve or synchronized 30 Minute Reserve that is scheduled by RTD and is not located in Southeastern New York; and (ii) the original market clearing price calculated under Section 15.4.6.1 above.~~

~~The Eastern 10 Minute Non-Synchronized Reserve market clearing price shall be the higher of: (i) the highest Lost Opportunity Cost of any provider of synchronized 30 Minute Reserve that is scheduled by RTD and is not located in Southeastern New York; and (ii) the original market clearing price calculated under Section 15.4.6.1 above.~~

~~The Eastern 30 Minute Reserve market clearing price shall be the higher of: (i) the highest Lost Opportunity Cost of any provider of synchronized 30 Minute Reserve that is scheduled by RTD and is not located in Southeastern New York; and (ii) the original market clearing price calculated under Section 15.4.6.1 above.~~

~~The Southeastern Spinning Reserve market clearing price shall be the higher of: (i) the highest Lost Opportunity Cost of any provider of Spinning Reserve or synchronized 30 Minute Reserve that is scheduled by RTD and is not located on Long Island; and (ii) the original market clearing price calculated under Section 15.4.6.1 above.~~

~~The Southeastern 10 Minute Non-Synchronized Reserve market clearing price shall be the higher of: (i) the highest Lost Opportunity Cost of any provider of synchronized 30 Minute Reserve that is scheduled by RTD and is not located on Long Island; and (ii) the original market clearing price calculated under Section 15.4.6.1 above.~~

~~The Southeastern 30 Minute Reserve market clearing price shall be the higher of: (i) the highest Lost Opportunity Cost of any provider of synchronized 30 Minute Reserve that is scheduled by RTD and is not located on Long Island; and (ii) the original market clearing price calculated under Section 15.4.6.1 above.~~

~~The Western Spinning Reserve market clearing price shall be the higher of: (i) the highest Lost Opportunity Cost of any provider of Western Spinning Reserve or Western synchronized 30 Minute Reserves that is scheduled by RTD; and (ii) the original market clearing price calculated under Section 15.4.6.1 above.~~

~~The Western 10 Minute Non-Synchronized Reserve market clearing price shall be the higher of: (i) the highest Lost Opportunity Cost of any provider of Western synchronized 30 Minute Reserve that is scheduled by RTD; and (ii) the original market clearing price calculated under Section 15.4.6.1 above.~~

~~The Western 30 Minute Reserve market clearing price shall be the higher of: i) the highest Lost Opportunity Cost of any provider of Western synchronized 30 Minute Reserve that~~

~~is scheduled by RTD; and (ii) the original market clearing price calculated under Section 15.4.6.1 above.~~

~~15.4.6.2.2 Pricing Operating Reserves During Intervals of Eastern Scarcity~~

~~The Eastern Spinning Reserve market clearing price shall be the higher of: (i) the highest Lost Opportunity Cost of any provider of Eastern Spinning Reserve or Eastern synchronized 30-Minute Reserve that is scheduled by RTD and is not located in Southeastern New York; and (ii) the original market clearing price calculated under Section 15.4.6.1 above.~~

~~The Eastern 10-Minute Non-Synchronized Reserve market clearing price shall be the higher of: (i) the highest Lost Opportunity Cost of any provider of Eastern synchronized 30-Minute Reserve that is scheduled by RTD and is not located in Southeastern New York; and (ii) the original market clearing price calculated under Section 15.4.6.1 above.~~

~~The Eastern 30-Minute Reserve market clearing price shall be the higher of: (i) the highest Lost Opportunity Cost of any provider of Eastern synchronized 30-Minute Reserve that is scheduled by RTD and is not located in Southeastern New York; and (ii) the original market clearing price calculated under Section 15.4.6.1 above.~~

~~The Southeastern Spinning Reserve market clearing price shall be the higher of: (i) the highest Lost Opportunity Cost of any provider of Eastern or Southeastern Spinning Reserve or Eastern or Southeastern synchronized 30-Minute Reserve that is scheduled by RTD and is not located on Long Island; and (ii) the original market clearing price calculated under Section 15.4.6.1 above.~~

~~The Southeastern 10-Minute Non-Synchronized Reserve market clearing price shall be the higher of: (i) the highest Lost Opportunity Cost of any provider of Eastern or Southeastern~~

~~synchronized 30-Minute Reserve that is scheduled by RTD and is not located on Long Island; and (ii) the original market clearing price calculated under Section 15.4.6.1 above.~~

~~The Southeastern 30-Minute Reserve market clearing price shall be the higher of: (i) the highest Lost Opportunity Cost of any provider of Eastern or Southeastern synchronized 30-Minute Reserve that is scheduled by RTD and is not located on Long Island; and (ii) the original market clearing price calculated under Section 15.4.6.1 above.~~

~~15.4.6.2.3 Pricing Operating Reserves During Intervals of Southeastern Scarcity~~

~~The Southeastern Spinning Reserve market clearing price shall be the higher of: (i) the highest Lost Opportunity Cost of any provider of Southeastern Spinning Reserve or Southeastern synchronized 30-Minute Reserve that is scheduled by RTD and is not located on Long Island; and (ii) the original market clearing price calculated under Section 15.4.6.1 above.~~

~~The Southeastern 10-Minute Non-Synchronized Reserve market clearing price shall be the higher of: (i) the highest Lost Opportunity Cost of any provider of Southeastern synchronized 30-Minute Reserve that is scheduled by RTD and is not located on Long Island; and (ii) the original market clearing price calculated under Section 15.4.6.1 above.~~

~~The Southeastern 30-Minute Reserve market clearing price shall be the higher of: (i) the highest Lost Opportunity Cost of any provider of Southeastern synchronized 30-Minute Reserve that is scheduled by RTD and is not located on Long Island; and (ii) the original market clearing price calculated under Section 15.4.6.1 above.~~

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, ~~or~~ 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, ~~D~~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 ~~locational~~ 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~~²⁵/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.

- (1) 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.

17.1 LBMP Calculation

The Locational Based Marginal Prices (“LBMPs” or “prices”) for Suppliers and Loads in the Real-Time Market will be based on the system marginal costs produced by the Real-Time Dispatch (“RTD”) program and during intervals when certain conditions exist at Proxy Generator Buses, the Real-Time Commitment (“RTC”) program. LBMPs for Suppliers and Loads in the Day-Ahead Market will be based on the system marginal costs produced by the Security Constrained Unit Commitment (“SCUC”). LBMPs calculated by SCUC and RTD will incorporate the incremental dispatch costs of Resources that would be scheduled to meet an increment of Load and, to the extent that tradeoffs exist between scheduling providers to produce Energy or reduce demand, and scheduling them to provide Regulation Service or Operating Reserves, LBMPs shall reflect the effect of meeting an increment of Load, given those tradeoffs, at each location on the Bid Production Cost associated with those services. As such, those LBMPs may incorporate: (i) Bids for Regulation Service or Operating Reserves; or (ii) shortage costs associated with the inability to meet a Regulation Service or Operating Reserves requirement under the Regulation Service Demand Curve [set forth in Rate Schedule 3 of this ISO Services Tariff](#) and Operating Reserve Demand Curves [and Scarcity Reserve Demand Curve set forth in Rate Schedules ~~3 and 4~~ respectively](#) of this ISO Services Tariff.

Additionally, for the purpose of calculating Real-Time LBMPs when RTD is committing and dispatching Resources meeting Minimum Generation Levels and capable of starting in ten minutes pursuant to Section 4.4.3.3 of this ISO Services Tariff, RTD shall include in the incremental dispatch cost of each such Resource a start-up cost based on the Start-Up Bid of each such Resource and shall assume for each such Resource a zero downward response rate.

17.1.1 LBMP Bus Calculation Method

System marginal costs will be utilized in an *ex ante* computation to produce Day-Ahead and Real-Time LBMP bus prices using the following equations.

The LBMP at bus i can be written as:

$$\gamma_i = \lambda^R + \gamma_i^L + \gamma_i^C$$

Where:

γ_i	=	LBMP at bus i in \$/MWh
λ^R	=	the system marginal price at the Reference Bus
γ_i^L	=	Marginal Losses Component of the LBMP at bus i which is the marginal cost of losses at bus i relative to the Reference Bus
γ_i^C	=	Congestion Component of the LBMP at bus i which is the marginal cost of Congestion at bus i relative to the Reference Bus

The Marginal Losses Component of the LBMP at any bus i is calculated using the equation:

$$\gamma_i^L = (DF_i - 1)\lambda^R$$

Where:

DF_i = delivery factor for bus i to the system Reference Bus and:

$$DF_i = \left(1 - \frac{\partial L}{\partial P_i}\right)$$

Where:

L	=	NYCA losses; and
P_i	=	injection at bus i

The Congestion Component of the LBMP at bus i is calculated using the equation:

$$\gamma_i^c = - \left(\sum_{k \in K}^n GF_{ik} \mu_k \right)$$

~~except as noted in Sections 17.1.2.2.1 and 17.1.2.3.1 of this Attachment B~~

Where:

K = the set of Constraints;

GF_{ik} = Shift Factor for bus i on Constraint k in the pre- or post-Contingency case which limits flows across that Constraint (the Shift Factor measures the incremental change in flow on Constraint k , expressed in per unit, for an increment of injection at bus i and a corresponding withdrawal at the Reference Bus); and

μ_k = the Shadow Price of Constraint k expressed in \$/MWh, provided however, this Shadow Price shall not exceed the Transmission Shortage Cost.

Substituting the equations for γ_i^L and γ_i^C into the first equation yields:

$$\gamma_i = \lambda^R + (DF_i - 1)\lambda^R - \sum_{k \in K} GF_{ik} \mu_k$$

LBMPs will be calculated for the Day-Ahead and the Real-Time Markets. In the Day-Ahead Market, the three components of the LBMP at each location will be calculated from the SCUC results and posted for each of the twenty four (24) hours of the next day. The Real-Time LBMPs will be calculated and posted for each execution of RTD.

17.1.1.1 Determining Shift Factors and Incremental System Losses

For the purposes of pricing and scheduling, Shift Factors, GF_{ik} , and loss delivery factors, DF_i , will reflect expected power flows, including expected unscheduled power flows. When determining prices and schedules, SCUC, RTC and RTD shall include both the expected power flows resulting from NYISO interchange schedules (*see* Section 17.1.1.1.2), and expected unscheduled power flows (*see* Section 17.1.1.1.1). All NYCA Resource, NYCA Load and Proxy Generator Bus Shift Factors and loss delivery factors will incorporate internal and coordinated

external transmission facility outages, power flows due to schedules, and expected unscheduled power flows.

17.1.1.1.1 Determining Expected Unscheduled Power Flows

In the Day-Ahead Market, expected unscheduled power flows will ordinarily be determined based on historical, rolling 30-day on-peak and off-peak averages. To ensure expected unscheduled power flows accurately reflect anticipated conditions, the frequency and/or period used to determine the historical average may be modified by the NYISO to address market rule, system topology, operational, or other changes that would be expected to significantly impact unscheduled power flows. The NYISO will publicly post the Day-Ahead on-peak and off-peak unscheduled power flows on its web site.

In the Real-Time Market, expected unscheduled power flows will ordinarily be determined based on current power flows, modified to reflect expected changes over the real-time scheduling horizon.

17.1.1.1.2 Determining Expected Power Flows Resulting from NYISO Interchange Schedules

In the Day-Ahead Market, for purposes of scheduling and pricing, SCUC will establish expected power flows for the ABC interface, JK interface and Branchburg-Ramapo interconnection based on the following:

- a. Consolidated Edison Company of New York's Day-Ahead Market hourly election under OATT Attachment CC, Schedule C;
- b. The percentage of PJM-NYISO scheduled interchange that is expected to flow over the Branchburg-Ramapo interconnection. The expected flow may also be adjusted by a MW offset to reflect expected operational conditions;

- c. The percentage of PJM-NYISO scheduled interchange (if any) that is expected to flow over the ABC interface; and
- d. The percentage of PJM-NYISO scheduled interchange (if any) that is expected to flow over the JK interface.

The terms “ABC interface” and “JK interface” have the meaning ascribed to them in Schedule C to Attachment CC to the OATT.

The NYISO shall post the percentage values it is currently using to establish Day-Ahead and real-time expected Branchburg-Ramapo interconnection, ABC interface and JK interface flows for purposes of scheduling and pricing on its web site. If the NYISO determines it is necessary to change the posted Branchburg-Ramapo, ABC or JK percentage values, it will provide notice to its Market Participants as far in advance of the change as is practicable under the circumstances.

In the Day-Ahead Market, scheduled interchange that is not expected to flow over the ABC interface, JK interface or Branchburg-Ramapo interconnection (or on Scheduled Lines) will be expected to flow over the NYISO’s other interconnections. Expected flows over the NYISO’s other interconnections will be determined consistent with the expected impacts of scheduled interchange and consistent with shift factors and delivery factors calculated in accordance with Section 17.1.1.1, above.

For pricing purposes, flows in the Real-Time Market will be established for the ABC interface, JK interface, and Branchburg-Ramapo interconnection based on the current flow, modified to reflect the expected incremental impacts of changes to interchange schedules over the forward scheduling horizon in a manner that is consistent with the method used to establish Day-Ahead power flows over these facilities. Expected flows over the NYISO’s other

interconnections will be determined based on the current flow, modified to reflect the expected incremental impacts of changes to interchange schedules over the forward scheduling horizon, and shall be consistent with shift factors and delivery factors calculated in accordance with Section 17.1.1.1, above.

17.1.1.1.3 Scheduled Lines and Chateaugay Interconnection with Hydro Quebec

For purposes of scheduling and pricing, the NYISO expects that power flows will ordinarily match the interchange schedule at Scheduled Lines, and at the NYCA's Chateaugay interconnection with Hydro Quebec, in both the Day-Ahead and Real-Time Markets.

17.1.2 Real-Time LBMP Calculation Procedures

For each RTD interval, the ISO shall use the procedures described below in Sections 17.1.2.1-17.1.2.1.4 to calculate Real-Time LBMPs at each Load Zone and Generator bus. The LBMP bus and zonal calculation procedures are described in Sections 17.1.1 and 17.1.5 of this Attachment B, respectively. Procedures governing the calculation of LBMPs at Proxy Generator Buses are set forth below in Section 17.1.6 of this Attachment B. ~~In addition, when certain scarcity conditions exist, as defined below, the ISO shall employ the special scarcity pricing rules described in Section 17.1.2.2. The NYISO shall use the scarcity pricing rule described in 17.1.2.2 for each interval in which EDRP/SCR Resources have been called in one or more Load Zones due to a reliability need and the aggregate of Available Reserves in the Load Zone(s) in which the reliability need was identified are less than the number of EDRP/SCR MW called for that event.~~

17.1.2.1 General Procedures

17.1.2.1.1 Overview

The ISO shall calculate Real-Time Market LBMPs using the three passes of each RTD run, except as noted below in Section 17.1.1.1.3. A new RTD run will initialize every five minutes and each run will produce prices and schedules for five points in time (the optimization period). Only the prices and schedules determined for the first time point of the optimization period will be binding. Prices and schedules for the other four time points of the optimization period are advisory.

Each RTD run shall, depending on when it occurs during the hour, have a bid optimization horizon of fifty, fifty-five, or sixty minutes beyond the first, or binding, point in time that it addresses. The posting time and the first time point in each RTD run, which establishes binding prices and schedules, will be five minutes apart. The remaining points in time in each optimization period can be either five, ten, or fifteen minutes apart depending on when the run begins within the hour. The points in time in each RTD optimization period are arranged so that they parallel as closely as possible RTC's fifteen minute evaluations.

For example, the RTD run that posts its results at the beginning of an hour ("RTD₀") will initialize at the fifty-fifth minute of the previous hour and produce schedules and prices over a fifty-five minute optimization period. RTD₀ will produce binding prices and schedules for the RTD interval beginning when it posts its results (i.e., at the beginning of the hour) and ending at the first time point in its optimization period (i.e., five minutes after the hour). It will produce advisory prices and schedules for its second time point, which is ten minutes after the first time point in its optimization period, and advisory prices and schedules for its third, fourth and fifth time points, each of which would be fifteen minutes apart. The RTD run that posts its results at five minutes after the beginning of the hour ("RTD₅") will initialize at the beginning of the hour

and produce prices over a fifty minute optimization period. RTD_5 will produce binding prices and schedules for the RTD interval beginning when it posts its results (i.e., at five minutes after the hour) and ending at the first time point in its optimization period (i.e., ten minutes after the hour.) It will produce advisory prices and schedules for its second time point (which is five minutes after the first time point), and advisory prices and schedules for its third, fourth and fifth time points, each of which would be fifteen minutes apart. The RTD run that posts its results at ten minutes after the beginning of the hour (" RTD_{10} ") will initialize at five minutes after the beginning of the hour and produce prices over a sixty minute optimization period. RTD_{10} will produce binding prices and schedules for the interval beginning when it posts its results (i.e., at ten minutes after the hour) and ending at the first time point in its optimization period (i.e., fifteen minutes after the hour.) It will produce advisory prices and schedules for its second, third, fourth and fifth time points, each of which would be fifteen minutes after the preceding time point.

17.1.2.1.2 Description of the Real-Time Dispatch Process

17.1.2.1.2.1 The First Pass

The first RTD pass consists of a least bid cost, multi-period co-optimized dispatch for Energy, Regulation Service and Operating Reserves that treats all Fixed Block Units that are committed by RTC, or are otherwise instructed to be online or remain online by the ISO as if they were blocked on at their UOL_N or UOL_E , whichever is applicable. Resources meeting Minimum Generation Levels and capable of being started in ten minutes that have not been committed by RTC are treated as flexible (i.e. able to be dispatched anywhere between zero (0) MW and their UOL_N or UOL_E , whichever is applicable). The first pass establishes "physical base points" (i.e., real-time Energy schedules) and real-time schedules for Regulation Service

and Operating Reserves for the first time point of the optimization period. Physical base points and schedules established for the first time point shall be binding and shall remain in effect until the results of the next run are posted. Physical base points and schedules established for all subsequent time points shall be advisory. The first pass also produces information that is used to calculate the RTD Base Point Signals that the ISO sends to Suppliers.

When establishing physical base points, the ISO shall assume that each Generator will move toward the physical base point established during the first pass of the prior RTD run at its specified response rate.

17.1.2.1.2.1.1 Upper and Lower Dispatch Limits for Dispatchable Resources Other Than Intermittent Power Resources That Depend on Wind as Their Fuel

When setting physical base points for a Dispatchable Resource at the first time point, the ISO shall ensure that they do not fall outside of the bounds established by the Dispatchable Resource's lower and upper dispatch limits. A Dispatchable Resource's dispatch limits shall be determined based on whether it was feasible for it to reach the physical base point calculated by the last RTD run given its: (A) metered output level at the time that the RTD run was initialized; (B) response rate; (C) minimum generation level; and (D) UOL_N or UOL_E , whichever is applicable. If it was feasible for the Dispatchable Resource to reach that base point, then its upper and lower dispatch limits shall reflect the highest and lowest output levels it could achieve over the next RTD interval, given its UOL_N or UOL_E , as applicable, and starting from its previous base point. If it was not feasible for the Dispatchable Resource to reach that base point, then its upper and lower dispatch limits shall reflect the highest and lowest output levels it could achieve over the next RTD interval, given its UOL_N or UOL_E , as applicable, but instead starting from the feasible output level closest to its previous base point.

When setting physical base points for a Dispatchable Resource at later time points, the ISO shall ensure that they do not fall outside of the bounds established by the Resource's lower and upper dispatch limits for that time point. A Resource's dispatch limits at later time points shall be based on its: (A) dispatch limits from the first time point; (B) response rate; (C) minimum generation; and (D) UOL_N or UOL_E , whichever is applicable.

The upper dispatch limit for a Dispatchable Resource at later time points shall be determined by increasing the upper dispatch limit from the first time point at the Resource's response rate, up to its UOL_N or UOL_E , whichever is applicable. The lower dispatch limit for a Dispatchable Resource at later time points shall be determined by decreasing the lower dispatch limit from the first time point at the Resource's response rate, down to its minimum generation level or to a Demand Side Resource's Demand Reduction level.

The RTD Base Point Signals sent to Dispatchable Resources shall be the same as the physical base points determined above.

17.1.2.1.2.1.2 Upper and Lower Dispatch Limits for Intermittent Power Resources That Depend on Wind as Their Fuel

For all time points of the optimization period, the Lower Dispatch Limit shall be zero and the Upper Dispatch Limit shall be the Wind Energy Forecast for that Resource. For Intermittent Power Resources depending on wind as their fuel in commercial operation as of January 1, 2002 with a name plate capacity of 12 MWs or fewer, the Upper and Lower Dispatch Limits shall be the output level specified by the Wind Energy Forecast.

17.1.2.1.2.1.3. Setting Physical Basepoints for Fixed Generators

When setting physical base points for Self-Committed Fixed Generators in any time point, the ISO shall consider the feasibility of the Resource reaching the output levels that it

specified in its self-commitment request for each time point in the RTD run given: (A) its metered output at the time that the run was initialized; and (B) its response rate.

When setting physical base points for ISO-Committed Fixed Generators in any time point, the ISO shall consider the feasibility of the Resource reaching the output levels scheduled for it by RTC for each time point in the RTD run given: (A) its metered output at the time that the run was initialized; and (B) its response rate.

The RTD Base Point Signals sent to Self-Committed Fixed Generators shall follow the quarter hour operating schedules that those Generators submitted in their real-time self-commitment requests

The RTD Base Point Signals sent to ISO-Committed Fixed Generators shall follow the quarter hour operating schedules established for those Generators by RTC, regardless of their actual performance. To the extent possible, the ISO shall honor the response rates specified by such Generators when establishing RTD Base Point Signals. If a Self-Committed Fixed Generator's operating schedule is not feasible based on its real-time self-commitment requests then its RTD Base Point Signals shall be determined using a response rate consistent with the operating schedule changes.

17.1.2.1.2.2 The Second Pass

The second RTD pass consists of a least bid cost, multi-period, co-optimized dispatch for Energy, Regulation Service, and Operating Reserves that treats all Fixed Block Units that are committed by RTC, all Resources meeting Minimum Generation Levels and capable of starting in ten minutes that have not been committed by RTC and all units otherwise instructed to be online or remain online by the ISO, as flexible (i.e., able to be dispatched anywhere between zero (0) MW and their UOL_N or UOL_E , whichever is applicable), regardless of their minimum run-

time status. This pass shall establish “hybrid base points” (i.e., real-time Energy schedules) that are used in the third pass to determine whether minimum run-time constrained Fixed Block Units should be blocked on at their UOL_N or UOL_E , whichever is applicable, or dispatched flexibly. The ISO will not use schedules for Energy, Regulation Service and Operating Reserves established in the second pass to dispatch Resources.

The upper and lower dispatch limits used for ISO-Committed Fixed and Self-Committed Fixed Resources shall be the same as the physical base points calculated in the first pass.

17.1.2.1.2.2.1 Upper and Lower Dispatch Limits for Dispatchable Resources Other Than Intermittent Power Resources That Depend on Wind as Their Fuel

The upper dispatch limit for the first time point of the second pass for a Dispatchable Resource shall be the higher of: (A) its upper dispatch limit from the first pass; or (B) its “pricing base point” from the first time point of the prior RTD interval adjusted up within its Dispatchable range for any possible ramping since that pricing base point was issued less the higher of: (i) the physical base point established during the first pass of the RTD immediately prior to the previous RTD minus the Resource’s metered output level at the time that the current RTD run was initialized, or (ii) zero.

The lower dispatch limit for the first time point of the second pass for a Dispatchable Resource shall be the lower of: (A) its lower dispatch limit from the first pass; or (B) its “pricing base point” from the first time point of the prior RTD interval adjusted down within its Dispatchable range to account for any possible ramping since that pricing base point was issued plus the higher of: (i) the Resource’s metered output level at the time that the current RTD run was initialized minus the physical base point established during the first pass of the RTD immediately prior to the previous RTD; or (ii) zero.

The upper dispatch limit for the later time points of the second pass for a Dispatchable Resource shall be determined by increasing its upper dispatch limit from the first time point at the Resource's response rate, up to its UOL_N or UOL_E , whichever is applicable. The lower dispatch limit for the later time points of the second pass for such a Resource shall be determined by decreasing its lower dispatch limit from the first time point at the Resource's response rate, down to its minimum generation level.

17.1.2.1.2.2.2 Upper and Lower Dispatch Limits for Intermittent Power Resources That Depend on Wind as Their Fuel

For the first time point and later time points for Intermittent Power Resources that depend on wind as their fuel, the Lower Dispatch Limit shall be zero and the Upper Dispatch Limit shall be the Wind Energy Forecast for that Resource. For Intermittent Power Resources depending on wind as their fuel in commercial operation as of January 1, 2002 with a name plate capacity of 12 MWs or fewer, the Upper and Lower Dispatch Limits shall be the output level specified by the Wind Energy Forecast.

17.1.2.1.2.3 The Third Pass

The third RTD pass is the same as the second pass with three variations. First, the third pass treats Fixed Block Units that are committed by RTC, or are otherwise instructed to be online or remain online by the ISO that received a non-zero physical base point in the first pass, and that received a hybrid base point of zero in the second pass, as blocked on at their UOL_N or UOL_E , whichever is applicable. Second, the third pass produces "pricing base points" instead of hybrid base points. Third, and finally, the third pass calculates real-time Energy prices and real-time Shadow Prices for Regulation Service and Operating Reserves that the ISO shall use for settlement purposes pursuant to Article 4, Rate Schedule 15.3, and Rate Schedule 15.4 of this

ISO Services Tariff respectively. The ISO shall not use schedules for Energy, Regulation Service and Operating Reserves that are established in the third pass to dispatch Resources.

17.1.2.1.3 Variations in RTD-CAM

When the ISO activates RTD-CAM, the following variations to the rules specified above in Sections 17.1.2.1.1 and 17.1.2.1.2 shall apply.

First, if the ISO enters reserve pickup mode: (i) the ISO will produce prices and schedules for a single ten minute interval (not for a multi-point co-optimization period); (ii) the ISO shall set Regulation Service schedules to zero as described in Rate Schedule 15.3 of this ISO Services Tariff; (iii) the ISO will have discretion to make additional Generator commitments before executing the three RTD passes; and (iv) the ISO will have discretion to allow the RTD Base Point Signal of each Dispatchable Generator to be set to the higher of the Generator's physical base point or its actual generation level.

Second, if the ISO enters maximum generation pickup mode: (i) the ISO will produce prices and schedules for a single five minute interval (not for a multi-point co-optimization period); (ii) the ISO shall set Regulation Service schedules to zero as described in Rate Schedule 15.3 of this ISO Services Tariff; (iii) the ISO will have discretion to make additional Generator commitments in the affected area before executing the three RTD passes; and (iv) the ISO will have discretion to either move the RTD Base Point Signal of each Generator within the affected area towards its UOL_E at its emergency response rate or set it at a level equal to its physical base point.

Third, if the ISO enters basepoints ASAP – no commitments mode it will produce prices and schedules for a single five minute interval (not for a multi-point co-optimization period).

Fourth, if the ISO enters basepoints ASAP – commit as needed mode: (i) the ISO will produce price and schedules for a single five minute interval (not for a multi-point co-optimization period); and (ii) the ISO may make additional commitments of Generators that are capable of starting within ten minutes before executing the three RTD passes.

Fifth, and finally, if the ISO enters re-sequencing mode it will solve for a ten-minute optimization period consisting of two five-minute time points.

17.1.2.1.4 The Real-Time Commitment (“RTC”) Process and Automated Mitigation

Attachment H of this Services Tariff shall establish automated market power mitigation measures that may affect the calculation of Real-Time LBMPs. To the extent that these measures are implemented they shall be incorporated into the RTC software through the establishment of a second, parallel, commitment evaluation that will assess the impact of the mitigation measures. The first evaluation, referred to as the “RTC evaluation,” will determine the schedules and prices that would result using an original set of offers and Bids before any additional mitigation measures, the necessity for which will be considered in the RTC evaluation, are applied. The second evaluation, referred to as the “RT-AMP” evaluation, will determine the schedules and prices that would result from using the original set of offers and bids as modified by any necessary mitigation measures. Both evaluations will follow the rules governing RTC’s operation that are set forth in Article 4 and this Attachment B to this ISO Services Tariff.

In situations where Attachment H specifies that real-time automated mitigation measures be utilized, the ISO will perform the two parallel RTC evaluations in a manner that enables it to implement mitigation measures one RTC run (i.e., fifteen minutes) in the future. For example, RTC₁₅ and RT-AMP₁₅ will perform Resource commitment evaluations simultaneously. RT-

AMP₁₅ will then apply the mitigation “impact” test, account for reference bid levels as appropriate and determine which Resources are actually to be mitigated. This information will then be conveyed to RTC₃₀ which will make Resource commitments consistent with the application of the mitigation measures (and will thus indirectly be incorporated into future RTD runs).

~~17.1.2.2—Scarcity Pricing Rule~~

~~The ISO shall implement the following price calculation procedures for intervals when certain scarcity conditions exist as described in Section 17.1.2.~~

~~17.1.2.2.1 Except as noted in 17.1.2.2.2 below:~~

- ~~• The system marginal price at the Reference Bus shall be set pursuant to Section 17.1.2.1 of this Attachment B if the identified reliability need is not in Load Zone E. If the reliability need is in Load Zone E or in a set of Load Zones that includes Load Zone E, the system marginal price at the Reference Bus shall be the maximum Minimum Payment Nomination.~~
- ~~• The Marginal Losses Component of the LBMP at each location shall be calculated as the product of the system marginal price at the Reference Bus produced by RTD and a quantity equal to the delivery factor produced by RTD for that location minus one as defined in Section 17.1.1 of this Attachment.~~
- ~~• The Congestion Component of the LBMP at each location in a Load Zone(s) in which the reliability need was identified shall be set to the maximum Minimum Payment Nomination minus the system marginal price at the Reference Bus calculated pursuant to this Section 17.1.2.2.1.~~

- ~~The Congestion Component of the LBMP at all other locations shall be set equal to Congestion Component for that location produced by RTD, minus the result of subtracting: i) the system marginal price at the Reference Bus produced by RTD from ii) the system marginal price at the Reference Bus calculated pursuant to this Section 17.1.2.2.1.~~

- ~~The LBMP at each location shall be as defined in Section 17.1.1 of this Attachment: the sum of the Marginal Losses Component of the LBMP at that location, plus the Congestion Component of the LBMP at that location, plus the LBMP at the Reference Bus.~~

~~17.1.2.2.2 However, the ISO shall not use the pricing rules of Section 17.1.2.2.1 to set the LBMP for any location lower than the LBMP for that Load Zone or Generator bus calculated pursuant to Section 17.1.2.1, above. In cases in which the pricing in Section 17.1.2.2.1 above would cause this rule to be violated:~~

- ~~The LBMP at each location (including the Reference Bus) shall be set to the greater of the LBMP calculated for that location pursuant to Section 17.1.2.1 of this Attachment B; or the LBMP calculated for that location using the scarcity pricing rule established in Section 17.1.2.2.1.~~

- ~~The Marginal Losses Component of the LBMP at each location shall be calculated as the product of the system marginal price at the Reference Bus produced by RTD and a quantity equal to the delivery factor produced by RTD for that location minus one.~~

- ~~• The Congestion Component of the LBMP at each location shall be calculated as the LBMP at that location, minus the LBMP at the Reference Bus, minus the Marginal Losses Component of the LBMP at that location.~~

17.1.3 Day-Ahead LBMP Calculation Procedures

LBMPs in the Day-Ahead Market are calculated using five passes. The first two passes are commitment and dispatch passes; the last three are dispatch only passes.

Pass 1 consists of a least cost commitment and dispatch to meet Bid Load and reliable operation of the NYS Power System that includes Day-Ahead Reliability Units.

It consists of several steps. Step 1A is a complete Security Constrained Unit Commitment (“SCUC”) to meet Bid Load. At the end of this step, committed Fixed Block Units, Imports, Exports, Virtual Supply, Virtual Load, Demand Side Resources and non-Fixed Block Units are dispatched to meet Bid Load with Fixed Block Units treated as dispatchable on a flexible basis. For mitigation purposes, LBMPs are calculated from this dispatch. Following Step 1A, SCUC tests for automated mitigation procedure (“AMP”) activation.

If AMP is activated, Step 1B tests to determine if the AMP will be triggered by mitigating offer prices subject to mitigation that exceed the conduct threshold to their respective reference prices. These mitigated offer prices together with all originally submitted offer prices not subject to automatic mitigation are then used to commit generation and dispatch energy to meet Bid Load. This step is another iteration of the SCUC process. At the end of Step 1B, committed Fixed Block Units, Imports, Exports, Virtual Supply, Virtual Load, Demand Side Resources, and non-Fixed Block Units are again dispatched to meet Bid Load using the same mitigated or unmitigated Bids used to determine the commitment to meet Bid Load, with Fixed Block Units treated as dispatchable on a flexible basis. For mitigation purposes, LBMPs are

again calculated from this dispatch. The LBMPs determined at the end of Step 1B are compared to the LBMPs determined at the end of Step 1A to determine the hours and zones in which the impact test is met.

In Step 1C, generation offer prices subject to mitigation that exceed the conduct threshold are mitigated for those hours and zones in which the impact test was met in Step 1B. The mitigated offer prices, together with the original unmitigated offer price of units whose offer prices were not subject to mitigation, or did not trigger the conduct or impact thresholds, are used to commit generation and dispatch energy to meet Bid Load. This step is also a complete iteration of the SCUC process. At the end of Step 1C, committed Fixed Block Units, Imports, Exports, virtual supply, virtual load, Demand Side Resources, and non-Fixed Block Units are again dispatched to meet Bid Load, with Fixed Block Units treated as dispatchable on a flexible basis. For mitigation purposes, LBMPs are again calculated from this dispatch.

All Demand Side Resources and non-Fixed Block Units committed in the final step of Pass 1 (which could be either step 1A, 1B, or 1C depending on activation of and the AMP) are blocked on at least to minimum load in Passes 4 through 6. The resources required to meet local system reliability are determined in Pass 1.

Pass 2 consists of a least cost commitment and dispatch of Fixed Block Units, Imports, Exports, Demand Side Resources and non-Fixed Block Units to meet forecast Load requirements in excess of Bid Load, considering the Wind Energy Forecast, that minimizes the cost of incremental Minimum Generation and Start Up Bids, given revenues for Minimum Generation Energy based on LBMPs calculated in Pass 1, and assumes all Fixed Block Units are dispatchable on a flexible basis. Incremental Import Capacity needed to meet forecast Load requirements is determined in Pass 2. Fixed Block Units committed in this pass are not included

in the least cost dispatches of Passes 5 or 6. Demand Side Resources and non-Fixed Block Units committed in this step are blocked on at least to minimum Load in Passes 4 through 6.

Intermittent Power Resources that depend on wind as their fuel committed in this pass as a result of the consideration of the Wind Energy Forecast are not blocked in Passes 5 or 6.

Pass 3 is reserved for future use.

Pass 4 consists of a least cost dispatch to forecast Load. It is not used to set schedules or prices. It is used for operational purposes and provides a dispatch of Fixed Block Units, Imports, Exports, Demand Side Resources and non-Fixed Block Units committed in Passes 1 or 2. Incremental Import Capacity committed in Pass 2 is re-evaluated and may be reduced if no longer required.

Pass 5 consists of a least cost dispatch of Fixed Block Units, Imports, Exports, Virtual Supply, Virtual Load, Demand Side Resources and non-Fixed Block Units committed to meet Bid Load, based where appropriate on offer prices as mitigated in Pass 1. Fixed Block Units are treated as dispatchable on a flexible basis. LBMPs used to settle the Day-Ahead Market are calculated from this dispatch. The Shadow Prices used to compute Day-Ahead Market clearing prices for Regulation Service and for Operating Reserves in Rate Schedules 3 and 4 of this ISO Services Tariff are also calculated from this dispatch. Final schedules for all Imports, Exports, Virtual Supply, Virtual Load, Demand Side Resources and non-Fixed Block Units in the Day-Ahead Market are calculated from this dispatch.

Pass 6 consists of a least cost dispatch of all Day-Ahead committed Resources, Imports, Exports, Virtual Supply, Virtual Load, based where appropriate on offer prices as mitigated in Pass 1, with the schedules of all Fixed Block Units committed in the final step of Pass 1 blocked

on at maximum Capacity. Final schedules for Fixed Block Units in the Day-Ahead Market are calculated from this dispatch.

17.1.4 Determination of Transmission Shortage Cost

The Transmission Shortage Costs represent the limits on system costs associated with efficient dispatch to meet a particular Constraint. It is the maximum Shadow Price that will be used in calculating LBMPs under various levels of relaxation.

The ISO may periodically evaluate the Transmission Shortage Costs to determine whether it is necessary to modify the Transmission Shortage Costs to avoid future operational or reliability problems. The ISO will consult with its Market Monitoring Unit after it conducts this evaluation. If the ISO determines that it is necessary to modify the Transmission Shortage Costs in order to avoid future operational or reliability problems the resolution of which would otherwise require recurring operator intervention outside normal market scheduling procedures, in order to avoid among other reliability issues, a violation of NERC Interconnection Reliability Operating Limits or System Operating Limits, it may temporarily modify it for a period of up to ninety days, provided however the NYISO shall file such change with the Commission pursuant to Section 205 of the Federal Power Act within 45 days of such modification. If circumstances reasonably allow, the ISO will consult with its Market Monitoring Unit, the Business Issues Committee, the Commission, and the PSC before implementing any such modification. In all circumstances, the ISO will consult with those entities as soon as reasonably possible after implementing a temporary modification and shall explain the reasons for the change.

The responsibilities of the ISO and the Market Monitoring Unit in evaluating and modifying the Transmission Shortage Costs, as necessary are addressed in Attachment O, Section 30.4.6.8.1 of this Market Services Tariff (“Market Monitoring Plan”).

17.1.5 Zonal LBMP Calculation Method

The computation described in Section 17.1.1 of this Attachment B is at the bus level. An eleven (11) zone model will be used for the LBMP billing related to Loads. The LBMP for a zone will be a Load weighted average of the Load bus LBMPs in the Load Zone. The Load weights which will sum to unity will be calculated from the load bus MW distribution. Each component of the LBMP for a zone will be calculated as a Load weighted average of the Load bus LBMP components in the zone. The LBMP for a zone j can be written as:

$$\gamma_j^Z = \lambda^R + \gamma_j^{L,Z} + \gamma_j^{C,Z}$$

where:

$\gamma_j^Z =$	LBMP for zone j,
$\gamma_j^{L,Z} = \sum_{i=1}^n W_i \gamma_i^L$	is the Marginal Losses Component of the LBMP for zone j;
$\gamma_j^{C,Z} = \sum W_i \gamma_i^L$	is the Congestion Component of the LBMP for zone j;
$n =$	number of Load buses in zone j for which LBMPs are calculated; and
$W_i =$	Load weighting factor for bus i.

The NYISO also calculates and posts zonal LBMP for four (4) external zones for informational purposes only. Settlements for External Transactions are determined using the Proxy Generator Bus LBMP. Each external zonal LBMP is equal to the LBMP of the Proxy Generator Bus associated with that external zone. The table below identifies which Proxy Generator Bus LBMP is used to determine each of the posted external zonal LBMPs.

External Zone	External Zone PTID	Proxy Generator Bus	Proxy Generator Bus PTID
HQ	61844	HQ_GEN_WHEEL	23651
NPX	61845	N.E._GEN_SANDY_POND	24062
OH	61846	O.H._GEN_BRUCE	24063
PJM	61847	PJM_GEN_KEYSTONE	24065

Consistent with the ISO Services Tariff, LBMPs at Proxy Generator Buses are determined using calculated bus prices as described in this Section 17.1.

17.1.6 Real Time LBMP Calculation Methods for Proxy Generator Buses, Non-Competitive Proxy Generator Buses and Proxy Generator Buses Associated with Designated Scheduled Lines

17.1.6.1 Definitions

Interface ATC Constraint: An Interface ATC Constraint exists when proposed economic transactions over an Interface between the NYCA and the Control Area with which one or more Proxy Generator Bus(es) are associated would exceed the transfer capability for the Interface or for an associated Proxy Generator Bus.

Interface Ramp Constraint: An Interface Ramp Constraint exists when proposed interchange schedule changes pertaining to an Interface between the NYCA and the Control Area with which one or more Proxy Generator Bus(es) are associated would exceed any Ramp Capacity limit imposed by the ISO for the Interface or for an associated Proxy Generator Bus.

NYCA Ramp Constraint: A NYCA Ramp Constraint exists when proposed interchange schedule changes pertaining to the NYCA as a whole would exceed any Ramp Capacity limits in place for the NYCA as a whole.

Proxy Generator Bus Constraint: Any of an Interface ATC Constraint, an Interface Ramp Constraint, or a NYCA Ramp Constraint (individually and collectively).

External Interface Congestion: The product of: (i) the portion of the Congestion Component of the LBMP at a Proxy Generator Bus that is associated with a Proxy Generator Bus Constraint and (ii) a factor, between zero and 1, calculated pursuant to ISO Procedures.

Proxy Generator Bus Border LBMP: The LBMP at a Proxy Generator Bus minus External Interface Congestion at that Proxy Generator Bus.

Unconstrained RTD LBMP: The LBMP as calculated by RTD less any congestion associated with a Proxy Generator Bus Constraint.

17.1.6.2 General Rules

Transmission Customers and Customers with External Generators and Loads can bid into the LBMP Market or participate in Bilateral Transactions. Those with External Generators may arrange LBMP Market sales and/or Bilateral Transactions with Internal or External Loads and External Loads may arrange LBMP Market purchases and/or Bilateral Transactions with Internal Generators.

The Generator and Load locations for which LBMPs will be calculated will initially be limited to a pre-defined set of Proxy Generator Buses. LBMPs will be calculated for each Proxy Generator Bus within this limited set. When an Interface with multiple Proxy Generator Buses is constrained, the ISO will apply the constraint to all of the Proxy Generator Buses located at that Interface. Except as set forth in Sections 17.1.6.3 and 17.1.6.4, the NYISO will calculate the three components of LBMP for Transactions at a Proxy Generator Bus as provided in the tables below.

When determining the External Interface Congestion, if any, to apply to determine the LBMP for RTD intervals that bridge two RTC intervals, the NYISO shall use the External Interface Congestion associated with the second (later) RTC interval.

17.1.6.2.1 Pricing rules for Dynamically Scheduled Proxy Generator Buses

The pricing rules for Dynamically Scheduled Proxy Generator Buses are to be determined.

17.1.6.2.2 Pricing rules for Variably Scheduled Proxy Generator Buses

The pricing rules for Variably Scheduled Proxy Generator Buses are provided in the following table.

Rule No.	Proxy Generator Bus Constraint affecting External Schedules at location a	Direction of Proxy Generator Bus Constraint	Real-Time Pricing Rule (for location a)
1	Unconstrained in RTC_{15} , Rolling RTC and RTD	N/A	Real-Time $LBMP_a = RTD\ LBMP_a$
2	The Rolling RTC used to schedule External Transactions in a given 15-minute interval is subject to a Proxy Generator Bus Constraint	Into NYCA or out of NYCA (Import or Export)	Real-Time $LBMP_a = RTD\ LBMP_a + \text{Rolling RTC External Interface Congestion}_a$

17.1.6.2.3 Pricing rules for Proxy Generator Buses that are not Dynamically Scheduled or Variably Scheduled

The pricing rules for Proxy Generator Buses that are not Dynamically Scheduled or Variably Scheduled Proxy Generator Buses are provided in the following table.

Rule No.	Proxy Generator Bus Constraint affecting External Schedules at location a	Direction of Proxy Generator Bus Constraint	Real-Time Pricing Rule (for location a)
1	Unconstrained in RTC_{15} , Rolling RTC and RTD	N/A	Real-Time $LBMP_a = RTD\ LBMP_a$
3	RTC_{15} is subject to a Proxy Generator Bus Constraint	Into NYCA or out of NYCA (Import or Export)	Real-Time $LBMP_a = RTD\ LBMP_a + RTC_{15}\ \text{External Interface Congestion}_a$

17.1.6.3 Rules for Non-Competitive Proxy Generator Buses and Associated Interfaces

Real-Time LBMPs for an Interface that is associated with one or more Non-Competitive Proxy Generator Buses or for a Non-Competitive Proxy Generator Bus shall be determined as provided in the tables below. Non-Competitive Proxy Generator Buses are identified in Section 4.4.4 of the Services Tariff.

17.1.6.3.1 Pricing rules for Non-Competitive, Dynamically Scheduled Proxy Generator Buses

The pricing rules for Non-Competitive, Dynamically Scheduled Proxy Generator Buses are to be determined.

17.1.6.3.2 Pricing rules for Non-Competitive, Variably Scheduled Proxy Generator Buses

The pricing rules for Non-Competitive, Variably Scheduled Proxy Generator Buses are provided in the following table.

Rule No.	Proxy Generator Bus Constraint affecting External Schedules at location <i>a</i>	Direction of Proxy Generator Bus Constraint	Real-Time Pricing Rule (for location <i>a</i>)
1	Unconstrained in RTC ₁₅ , Rolling RTC and RTD	N/A	Real-Time $LBMP_a = RTD\ LBMP_a$
4	The Rolling RTC used to schedule External Transactions in a given 15-minute interval is subject to an Interface ATC or Interface RampConstraint	Into NYCA (Import)	<p>If Rolling RTC Proxy Generator Bus $LBMP_a > 0$, then Real-Time $LBMP_a = RTD\ LBMP_a + \text{Rolling RTC External Interface Congestion}_a$</p> <p>Otherwise, Real-Time $LBMP_a = \text{Minimum of (i) } RTD\ LBMP_a \text{ and (ii) zero}$</p>
5	The Rolling RTC used to schedule External Transactions in a given 15-minute interval is subject to an Interface ATC or Interface Ramp Constraint	Out of NYCA (Export)	<p>If Rolling RTC Proxy Generator Bus $LBMP_a < 0$, then Real-Time $LBMP_a = RTD\ LBMP_a + \text{Rolling RTC External Interface Congestion}_a$</p> <p>Otherwise, Real-Time $LBMP_a = RTD\ LBMP_a$</p>

17.1.6.3.3 Pricing rules for Non-Competitive Proxy Generator Buses that are not Dynamically Scheduled or Variably Scheduled Proxy Generator Buses

The pricing rules for Non-Competitive Proxy Generator Buses that are not Dynamically Scheduled or Variably Scheduled Proxy Generator Buses are provided in the following table.

Rule No.	Proxy Generator Bus Constraint affecting External Schedules at location a	Direction of Proxy Generator Bus Constraint	Real-Time Pricing Rule (for location a)
1	Unconstrained in RTC_{15} , Rolling RTC and RTD	N/A	Real-Time $LBMP_a = RTD\ LBMP_a$
6	RTC_{15} is subject to an Interface ATC or Interface Ramp Constraint	Into NYCA (Import)	If RTC_{15} Proxy Generator Bus $LBMP_a > 0$, then Real-Time $LBMP_a = RTD\ LBMP_a + RTC_{15}$ External Interface Congestion $_a$ Otherwise, Real-Time $LBMP_a =$ Minimum of (i) $RTD\ LBMP_a$ and (ii) zero
7	RTC_{15} is subject to an Interface ATC or Interface Ramp Constraint	Out of NYCA (Export)	If RTC_{15} Proxy Generator Bus $LBMP_a < 0$, then Real-Time $LBMP_a = RTD\ LBMP_a + RTC_{15}$ External Interface Congestion $_a$ Otherwise, Real-Time $LBMP_a = RTD\ LBMP_a$

17.1.6.4 Special Pricing Rules for Proxy Generator Buses Associated with Designated Scheduled Lines

Real-Time LBMPs for the Proxy Generator Buses associated with designated Scheduled Lines shall be determined as provided in the tables below. The Proxy Generator Buses that are associated with designated Scheduled Lines are identified in Section 4.4.4 of the Services Tariff.

17.1.6.4.1 Pricing rules for Dynamically Scheduled Proxy Generator Buses that are associated with Designated Scheduled Lines

The pricing rules for Dynamically Scheduled Proxy Generator Buses that are associated with designated Scheduled Lines are to be determined.

17.1.6.4.2 Pricing rules for Variably Scheduled Proxy Generator Buses that are associated with Designated Scheduled Lines

The pricing rules for Variably Scheduled Proxy Generator Buses that are associated with designated Scheduled Lines are provided in the following table.

Rule No.	Proxy Generator Bus Constraint affecting External Schedules at location <i>a</i>	Direction of Proxy Generator Bus Constraint	Real-Time Pricing Rule (for location <i>a</i>)
1	Unconstrained in RTC_{15} , Rolling RTC and RTD	N/A	Real-Time $LBMP_a = RTD\ LBMP_a$
4	The Rolling RTC used to schedule External Transactions in a given 15-minute interval is subject to an Interface ATC Constraint	Into NYCA (Import)	If Rolling RTC Proxy Generator Bus $LBMP_a > 0$, then Real-Time $LBMP_a = RTD\ LBMP_a + \text{Rolling RTC External Interface Congestion}_a$ Otherwise, Real-Time $LBMP_a = \text{Minimum of (i) } RTD\ LBMP_a \text{ and (ii) zero}$
5	The Rolling RTC used to schedule External Transactions in a given 15-minute interval is subject to an Interface ATC Constraint	Out of NYCA (Export)	If Rolling RTC Proxy Generator Bus $LBMP_a < 0$, then Real-Time $LBMP_a = RTD\ LBMP_a + \text{Rolling RTC External Interface Congestion}_a$ Otherwise, Real-Time $LBMP_a = RTD\ LBMP_a$

17.1.6.4.3 Pricing rules for Proxy Generator Buses that are associated with Designated Scheduled Lines that are not Dynamically Scheduled or Variably Scheduled Proxy Generator Buses

The pricing rules for Proxy Generator Buses that are associated with designated Scheduled Lines that are not Dynamically Scheduled or Variably Scheduled Proxy Generator Buses, are provided in the following table.

Rule No.	Proxy Generator Bus Constraint affecting External Schedules at location <i>a</i>	Direction of Proxy Generator Bus Constraint	Real-Time Pricing Rule (for location <i>a</i>)
1	Unconstrained in RTC_{15} , Rolling RTC and RTD	N/A	Real-Time $LBMP_a = RTD\ LBMP_a$
6	RTC_{15} is subject to an Interface ATC Constraint	Into NYCA (Import)	If RTC_{15} Proxy Generator Bus $LBMP_a > 0$, then Real-Time $LBMP_a = RTD\ LBMP_a + RTC_{15} \text{ External Interface Congestion}_a$ Otherwise, Real-Time $LBMP_a = \text{Minimum of (i) } RTD\ LBMP_a \text{ and (ii) zero}$

Rule No.	Proxy Generator Bus Constraint affecting External Schedules at location <i>a</i>	Direction of Proxy Generator Bus Constraint	Real-Time Pricing Rule (for location <i>a</i>)
7	RTC ₁₅ is subject to an Interface ATC Constraint	Out of NYCA (Export)	<p>If RTC₁₅ Proxy Generator Bus LBMP_a < 0, then Real-Time LBMP_a = RTD LBMP_a + RTC₁₅ External Interface Congestion_a</p> <p>Otherwise, Real-Time LBMP_a = RTD LBMP_a</p>

17.1.6.5 Method of Calculating Marginal Loss and Congestion Components of Real-Time LBMP at Non-Competitive Proxy Generator Buses and Proxy Generator Buses that are Subject to the Special Pricing Rule for Designated Scheduled Lines

Under the conditions specified below, the Marginal Losses Component and the Congestion Component of the Real-Time LBMP, calculated pursuant to the preceding paragraphs in Sections 17.1.6.3 and 17.1.6.4, shall be constructed as follows:

When the Real-Time LBMP is set to zero and that zero price was not the result of using the RTD, RTC or SCUC-determined LBMP;

$$\text{Marginal Losses Component of the Real-Time LBMP} = \text{Losses}_{\text{RTD PROXY GENERATOR BUS}}$$

and

$$\text{Congestion Component of the Real-Time LBMP} = -(\text{Energy}_{\text{RTD REF BUS}} + \text{Losses}_{\text{RTD PROXY GENERATOR BUS}})$$

where:

$\text{Energy}_{\text{RTD REF BUS}}$ = The marginal Bid cost of providing Energy at the reference Bus, as calculated by RTD for that 5-minute interval; and

$\text{Losses}_{\text{RTD PROXY GENERATOR BUS}}$ = The Marginal Losses Component of the LBMP as calculated by RTD for that 5-minute interval at the Non-Competitive Proxy Generator Bus or Proxy Generator Bus associated with a designated Scheduled Line.

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 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.

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 and cost calculations. 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).