# Attachment I

## 2.3 Definitions - C

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

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

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

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

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

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

**Capacity Accreditation Resource Class:** A defined set of Resources and/or Aggregations, as identified in accordance with ISO Procedures, with similar technologies and/or operating

characteristics which are expected to have similar marginal reliability contributions toward meeting NYSRC resource adequacy requirements for the upcoming Capability Year. Each Capacity Accreditation Resource Class will be evaluated through the annual review detailed in Section 5.12.14.3. Each Installed Capacity Supplier will be assigned a Capacity Accreditation Resource Class.

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

**Capacity Reservation Cap:** As defined in the ISO OATT.

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

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

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

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

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

**Combined Cycle Gas Turbine ("CCGT") Generator with Duct-Firing Capability:** A Combined Cycle Gas Turbine Generator equipped with duct burners, which add additional heat

to the steam used to produce additional electric power from the heat recovery steam generator and steam turbine(s).

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

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

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

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

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

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

For a Generator comprised of a group of generating units at a single location, which grouped generating units are separately committed and dispatched by the ISO, and for which Energy injections are measured at a single location, Compensable Overgeneration shall mean that quantity of Energy injected by the Generator, during the period when one of its grouped generating units is operating in a Start-Up or Shutdown Period, that

exceeds the Real-Time Scheduled Energy established by the ISO for that period, for that Generator, and for which the Generator may be paid pursuant to ISO Procedures.

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

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

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

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

**Congestion Rent**: As defined in the ISO OATT.

**Congestion Rent Shortfall**: As defined in the ISO OATT.

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

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

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

**Control Area System Resource:** A set of Resources owned or controlled by an entity within a Control Area that also is the operator of such Control Area. Entities supplying Unforced Capacity using Control Area System Resources will not designate particular Resources as the suppliers of Unforced Capacity.

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

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

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

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

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

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

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

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

To address the real-time variability of Energy deliveries from the Intermittent Power Resource or Limited Control Run-of-River Hydro Resource that participate as Co-located Storage Resources, when the participating Energy Storage Resource has a non-zero Regulation and/or Operating Reserves schedule or is dispatched to inject Energy, and the sum of the participating Energy Storage Resource's and the participating Intermittent Power Resource's or Limited Control Run-of-River Hydro Resource's Energy, Regulation Service and Operating Reserves Schedules is greater than or equal to a specified percentage of the CSR injection Scheduling Limit, then the ISO will issue a Wind and Solar Output Limit to the Intermittent Power Resource or Limited Control Run-of-River Hydro Resource to not exceed its Base Point Signal. The specified percentage that is ordinarily used will be posted on the ISO's website.

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

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

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

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

**CTS Sink Price:** The price at a CTS Sink.

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

**CTS Source Price:** The price at a CTS Source.

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

**Curtailment Customer Aggregator:** A Curtailment Services Provider that produces real-time verified reductions in NYCA load of at least 100 kW through contracts with retail end-users. The procedure for qualifying as a Curtailment Customer Aggregator is set forth in ISO procedures.

**Curtailment Initiation Cost:** The fixed payment, separate from a variable Demand Reduction Bid, required by a qualified Demand Reduction Provider in order to cover the cost of reducing demand.

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

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

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

## 2.12 Definitions - L

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

**Lower Operating Limit:** For an Energy Storage Resource or Aggregation containing Energy Storage Resources, the maximum amount of megawatts the Resource can consume from the grid, if it is bidding to withdraw Energy, or the minimum amount of MW the Resource can supply the grid if it is not bidding to withdraw Energy. The Lower Operating Limit of an ISO-Managed Energy Storage Resource that is not bidding to withdraw Energy shall not be set to less than 0 MW.

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

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

## 2.16 Definitions - P

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

**Primary Holder**: As defined in the ISO OATT.

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

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

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

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

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

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

## 4.2 Day-Ahead Markets and Schedules

### 4.2.1 Day-Ahead Load Forecasts, Bids and Bilateral Schedules

#### 4.2.1.1 General Customer Forecasting and Bidding Requirements

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

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

b. Bids to supply Ancillary Services;

c. Requests for Bilateral Transaction schedules;

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

e. Demand Reduction Bids; and

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

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

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

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

#### 4.2.1.2 Load Forecasts

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

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

##### 4.2.1.3.1 General Rules

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

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

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

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

If the Supplier using the ISO-Committed Flexible or Self-Committed Flexible bid mode is eligible to provide Regulation Service or Operating Reserves under Rate Schedules 3 and 4 respectively of this ISO Services Tariff, the Supplier's Bid may specify the quantity of Regulation Capacity it is making available and shall specify an emergency response rate that determines the quantity of Operating Reserves that it is capable of providing. For a Combined Cycle Gas Turbine Generator with Duct-Firing Capability that has opted for the Limiting Participation Flag, the Participation Limit and the emergency response rate will determine the quantity of 10-Minute Reserves that the Resource is capable of providing. Offers to provide Regulation Service and Operating Reserves must comply with the rules set forth in Rate Schedules 3 and 4 of this ISO Services Tariff. If a Supplier that is eligible to provide Operating

Reserves does not submit a Day-Ahead Availability Bid for Operating Reserves, its Day-Ahead Bid shall be rejected in its entirety. A Behind-the-Meter Net Generation Resource that is comprised of more than one generating unit, or an Aggregation containing at least one generating unit (unless all of the generating unit(s) use inverter-based energy storage technology) that is dispatched as a single aggregate unit at a single PTID is not qualified to provide Regulation Service or Spinning Reserves. Aggregations may only qualify to offer the Ancillary Services that all individual Resources in the Aggregation are qualified to provide. A Supplier may resubmit a complete Day-Ahead Bid, provided that the new Bid is timely. See Section 4.2.1.9 for bidding requirements for Demand Side Resources offering Energy in the Day-Ahead Market.

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

#### 4.2.1.3.2 Bid Parameters

Day-Ahead Bids by Suppliers using the ISO-Committed Flexible, Self-Committed Flexible or ISO-Committed Fixed bid modes may identify-variable Energy price Bids, consisting of up to eleven monotonically increasing, constant cost incremental Energy steps, and other parameters described in ISO Procedures. Day-Ahead Bids from Demand Side Resources offering Operating Reserves or Regulation Service shall be ISO-Committed Flexible and shall

have an Energy Bid price no lower than the Monthly Net Benefit Offer Floor. Day-Ahead Bids by Intermittent Power Resources that depend on wind or solar energy as their fuel shall be ISO-Committed Flexible and shall include a Minimum Generation Bid of zero megawatts and zero costs and a Start-Up Bid of zero cost.

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

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

When a Generator that submits a Minimum Generation Bid or that is a Fixed Block Unit participates as a Co-located Storage Resource, the ISO will treat the Generator as operating at, at least, its Minimum Generation Level (or full output for a Fixed Block Unit) for the purpose of

scheduling the Energy Storage Resource whenever the Generator is scheduled, including during start-up and shut-down periods.

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

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

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

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

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

In addition to the parameters that Suppliers submit for Energy Storage Resources because they are Generators, specific parameters may apply to some Bids for Energy Storage Resources.

Consistent with the ISO Procedures, Bids from Suppliers for Energy Storage Resources supplying Energy and Ancillary Services may be required to specify the Beginning Energy Level and the Energy Storage Resource's Roundtrip Efficiency, and must specify its Upper and Lower Storage Limits. The Energy Level for an Energy Storage Resource shall be managed by the Supplier unless the Supplier elects, in its Bids, to be ISO-Managed.

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

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

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

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

A Supplier may submit a Day-Ahead Market Self-Committed Fixed Bid for a DER Aggregation to withdraw Energy if the DER Aggregation includes at least one Withdrawal-

Eligible Generator. When a Self-Committed Fixed Bid for a DER Aggregation reflects both Energy supply and Energy withdrawals by a Withdrawal-Eligible Generator that is a component of the Aggregation, the DER Aggregation's Bid shall reflect the net offer, such that any Energy withdrawals reduce the Energy the DER Aggregation is capable of supplying.

#### 4.2.1.5 Bids to Supply Energy in Virtual Transactions

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

#### 4.2.1.6 Bids to Purchase Energy in Virtual Transactions

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

#### 4.2.1.7 Bilateral Transactions

Transmission Customers requesting Bilateral Transaction schedules shall identify hourly Transaction quantities (in MW) by Point of Injection and Point of Withdrawal, minimum run times associated with Firm Point-to-Point Transmission Service, if any, and shall provide other information (as described in ISO Procedures). A Generator can be the Point of Injection for a Bilateral Transaction. A Withdrawal-Eligible Generator can be the Point of Injection or the Point of Withdrawal for a Bilateral Transaction, but it cannot be both the Point of Injection and the Point of Withdrawal for the same Bilateral Transaction. An Aggregation containing one or more Withdrawal-Eligible Generators can be the Point of Injection or the Point of Withdrawal for a Bilateral Transaction, but it cannot be both the Point of Injection and the Point of

Withdrawal for the same Bilateral Transaction. An Aggregation containing one or more Demand Side Resources shall not be the Point of Injection or the Point of Withdrawal for a Bilateral Transaction.

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

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

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

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

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

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

### 4.2.2 ISO Responsibility to Establish a Statewide Load Forecast

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

### 4.2.3 Security Constrained Unit Commitment ("SCUC")

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

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

The schedule will include commitment of sufficient Generators and/or Demand Side Resources/Aggregations to provide for the safe and reliable operation of the NYS Power System. SCUC will treat Behind-the-Meter Net Generation Resources, Energy Storage Resources, and Aggregations as already being committed and available to be scheduled. Pursuant to ISO Procedures, the ISO may schedule any Resource to run above its $UOL_N$ up to the level of its $UOL_E$. In cases in which the sum of all Bilateral Schedules, excluding Bilateral Schedules for Transactions with Trading Hubs or Withdrawal-Eligible Generators as their POWs, and all Day-

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

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

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

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

Managed Energy Levels will continue to be rejected until the ISO reinstates the ISO-Managed Energy Level bid parameter, following notice.

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

#### 4.2.3.1 Reliability Forecast for the Dispatch Day

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

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

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

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

All Generator and/or Aggregation commitments made in the Day-Ahead Market pursuant to this Section 4.2.3.1 shall be posted on the ISO website following the close of the Day-Ahead Market, in accordance with ISO procedures. In addition, the ISO shall post on its website a non-binding, advisory notification of a request, or any modifications thereto, made pursuant to this Section 4.2.3.1 in the Day-Ahead Market by a Transmission Owner to commit a Generator and/or Aggregation that is located within a Constrained Area, as defined in Attachment H of this Services Tariff. The advisory notification shall be provided upon receipt of the request and in accordance with ISO procedures. The postings described here may be included with the operator-initiated commitment report that the ISO posts in accordance with Section 4.1.3.4 of this Services Tariff.

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

Prior to the Capability Period beginning May 1, 2025, in order to meet Load or reliability requirements in response to such changed conditions the ISO may: (i) commit additional Resources, beyond those committed Day-Ahead, using a SRE and considering (a) Bids submitted to the ISO that were not previously accepted but were designated by the bidder as continuing to be available; or (b) new Bids from all Suppliers, including neighboring systems; or (ii) take the following actions: (a) after providing notice, require all Resources to run above their $UOL_N$s, up to the level of their $UOL_E$s (pursuant to ISO Procedures) and/or raise the $UOL_N$s of Capacity

Limited Resources and Energy Limited Resources to their $UOL_E$ levels, or (b) cancel or reschedule transmission facility maintenance outages when possible. Actions taken by the ISO in performing supplemental commitments will not change any financial commitments that resulted from the Day-Ahead Market.

Beginning with the Capability Period beginning May 1, 2025, in order to meet Load or reliability requirements in response to such changed conditions the ISO may: (i) commit additional Resources, beyond those committed Day-Ahead, using a SRE and considering (a) Bids submitted to the ISO that were not previously accepted but were designated by the bidder as continuing to be available; or (b) new Bids from all Suppliers, including neighboring systems; or (ii) take the following actions: (a) after providing notice, require all Resources to run above their $UOL_{NS}$, up to the level of their $UOL_{ES}$ (pursuant to ISO Procedures) and/or raise the $UOL_{NS}$ of Energy Limited Resources to their $UOL_E$ levels, or (b) cancel or reschedule transmission facility maintenance outages when possible. Actions taken by the ISO in performing supplemental commitments will not change any financial commitments that resulted from the Day-Ahead Market.

### 4.2.4 Reliability Forecast for the Six Days Following the Dispatch Day

In the SCUC program, system operation shall be optimized based on Bids over the Dispatch Day. However, to preserve system reliability, the ISO must ensure that there will be sufficient resources available to meet forecasted Load and reserve requirements over the seven (7)-day period that begins with the next Dispatch Day. The ISO will perform a Supplemental Resource Evaluation ("SRE") for days two (2) through seven (7) of the commitment cycle. If it is determined that a long start-up time Generator (*i.e.*, a Generator that cannot be scheduled by SCUC to start up in time for the next Dispatch Day) is needed for reliability, the ISO shall accept

a Bid from the Generator and the Generator will begin its start-up sequence. During each day of the start-up sequence, the ISO will perform an SRE to determine if long start-up time Generators will still be needed as previously forecasted. If at any time it is determined that the Generator will not be needed as previously forecasted, the ISO shall order the Generator to abort its start-up sequence.

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

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

The ISO shall perform the SRE as follows: (1) The ISO shall develop a forecast of daily system peak Load for days two (2) through seven (7) in this seven (7)-day period and add the appropriate reserve margin; (2) the ISO shall then forecast its available Generators for the day in question by summing the Operating Capacity for all Generators currently in operation that are available for the commitment cycle, the Operating Capacity of all other Generators capable of starting on subsequent days to be available on the day in question, and an estimate of the net Imports from External Bilateral Transactions; (3) if the forecasted peak Load plus reserves exceeds the ISO's forecast of available Generators for the day in question, then the ISO shall commit additional Generators capable of starting prior to the day in question (*e.g.*, start-up period of two (2) days when looking at day three (3)) to assure system reliability; (4) in choosing

among Generators with comparable start-up periods, the ISO shall schedule Generators to minimize Minimum Generation Bid and Start-Up Bid costs of meeting forecasted peak Load plus Ancillary Services consistent with the Reliability Rules; (5) in determining the appropriate reserve margin for days two (2) through seven (7), the ISO will supplement the normal reserve requirements to allow for forced outages of the short start-up period units (*e.g.*, gas turbines) assumed to be operating at maximum output in the unit commitment analysis for reliability.

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

### 4.2.5 Post the Day-Ahead Schedule

By 11 a.m. on the day prior to the Dispatch Day, the ISO shall close the Day-Ahead scheduling process and post on the Bid/Post System the Day-Ahead schedule for each entity that submits a Bid or Bilateral Transaction schedule. All schedules shall be considered proprietary, with the posting only visible to the appropriate scheduling Customer and Transmission Owners subject to the applicable Code of Conduct (See Attachment F to the ISO OATT). The ISO will post on the OASIS the statewide aggregate resources (Day-Ahead Energy schedules and total operating capability forecast), Day-Ahead scheduled Load, forecast Load for each Load Zone,

and the Day-Ahead LBMP prices (including the Congestion Component and the Marginal Losses Component) for each Load Zone in each hour of the upcoming Dispatch Day. The ISO shall conduct the Day-Ahead Settlement based upon the Day-Ahead schedule determined in accordance with this section and Attachment B to this Services Tariff. The ISO will provide the Transmission Owner with the Load forecast (for seven (7) days) as well as the ISO security evaluation data to enable local area reliability to be assessed.

### 4.2.6 Day-Ahead LBMP Market Settlements

The ISO shall calculate the Day-Ahead LBMPs for each Load Zone and at each Generator bus and Demand Reduction Bus/Transmission Node as described in Attachment B. Each Supplier that bids a Generator or Aggregation into the ISO Day-Ahead Market and is scheduled in the SCUC to sell or purchase Energy in the Day-Ahead Market will be settled at the product of: (a) the Day-Ahead hourly LBMP at the applicable Generator bus or Transmission Node; and (b) the hourly Energy schedule. Each Supplier that bids an External Transaction into the Day-Ahead LBMP Market and is scheduled in the SCUC to sell Energy into the Day-Ahead LBMP Market will be settled at the product of (a) the Day-Ahead LBMP at the applicable Proxy Generator Bus and (b) the External Transaction schedule. For each Demand Reduction Provider that bids a Demand Reduction into the Day-Ahead Market and is scheduled in SCUC to provide Energy from the Demand Reduction, the LSE providing Energy service to the Demand Side Resource that accounts for the Demand Reduction shall be settled at the product of: (a) the Day-Ahead hourly LBMP at the applicable Demand Reduction Bus; and (b) the hourly demand reduction scheduled Day-Ahead (in MW). In addition, each Demand Reduction Provider that bids a Demand Reduction into the Day-Ahead Market and is scheduled in the SCUC to provide Energy through Demand Reduction shall receive a Demand Reduction Incentive Payment from

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

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

## 4.4 Real-Time Markets and Schedules

### 4.4.1 Real-Time Commitment ("RTC")

#### 4.4.1.1 Overview

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

#### 4.4.1.2 Bids and Other Requests

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

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

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

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

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

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

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

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

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

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

Incremental Energy Bids, for portions of the Capacity of Resources that were scheduled in the Day-Ahead Market, and/or Start-Up Bids may be submitted by Suppliers bidding Resources using ISO-Committed Fixed, ISO-Committed Flexible, and Self-Committed Flexible bid modes that exceed the Incremental Energy Bids or Start-Up Bids submitted in the Day-Ahead Market or the mitigated Day-Ahead Incremental Energy Bids or Start-Up Bids where appropriate, if not otherwise prohibited pursuant to other provisions of the tariff.

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

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

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

Suppliers bidding on behalf of Generators or Aggregations (except Aggregations comprised of only Intermittent Power Resources) that did not receive a Day-Ahead schedule for

a given hour may offer their Generators or Aggregations, for those hours, using the ISO-Committed Flexible, Self-Committed Flexible, Self-Committed Fixed bid mode or, with ISO approval, the ISO-Committed Fixed bid modes in real-time. For Behind-the-Meter Net Generation Resources, the ISO will consider only those segments of the Resource's Incremental Energy Bids above the forecasted Host Load and subject to the Injection Limit. 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 or Aggregation that received a Day-Ahead schedule for a given hour may not change the bidding mode for that Generator or Aggregation for the Real-Time Market for that hour provided, however, that Generators or Aggregations that were scheduled Day-Ahead in Self-Committed Fixed mode may switch, with ISO approval, to ISO-Committed Fixed bidding mode in real-time. Generators or Aggregations that were scheduled Day-Ahead in ISO-Committed Fixed mode will be scheduled as Self-Committed Fixed in the Real-Time Market unless, with ISO approval, they change their bidding mode to ISO-Committed Fixed.

Co-located Storage Resources must each submit a CSR injection Scheduling Limit and a CSR withdrawal Scheduling Limit for each hour of the Real-Time Market to indicate the expected capability of the relevant facilities. Resources that participate as CSR shall not submit Real-Time Market Bids that would self-commit either of the Generators, or both of the Generators together, to inject or to withdraw a quantity of Energy that exceeds an applicable CSR Scheduling Limit.

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

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

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

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

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

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

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

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

#### 4.4.1.2.3 Self-Commitment Requests

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

#### 4.4.1.2.4 ISO-Committed Fixed

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

RTC shall schedule ISO-Committed Fixed Generators.

### 4.4.1.3 External Transaction Scheduling

RTC15 will schedule External Transactions on an hourly basis as part of its development of a co-optimized least-bid cost Real-Time Commitment. For External Transactions that are scheduled on a 15 minute basis, the amount of Energy scheduled to be imported, exported or wheeled in association with that External Transaction may change on the quarter hour. All RTC runs will schedule intra-hour External Transactions on a 15 minute basis at Variably Scheduled

Proxy Generator Buses. RTC will alert the ISO when it appears that scheduled External Transactions need to be reduced for reliability reasons but will not automatically Curtail them. Curtailment decisions will be made by the ISO, guided by the information that RTC provides, pursuant to the rules established by Attachment B of this ISO Services Tariff and the ISO Procedures. External Bilateral Transaction schedules are also governed by the provisions of Section 16, Attachment J of the OATT.

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

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

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

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

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

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

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

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

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

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

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

(viii) Schedule ISO-Committed Fixed Resources.

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

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

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

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

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

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

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

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

(viii) Schedule ISO-Committed Fixed Resources.

#### 4.4.1.5 External Transaction Settlements

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

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

### 4.4.2 Real-Time Dispatch

#### 4.4.2.1 Overview

The Real-Time Dispatch will make dispatching decisions, send Base Point Signals to Internal Generators and Demand Side Resources/Aggregations, produce schedules for intra-hour External Transactions at Dynamically Scheduled Proxy Generator Buses, calculate Real-Time Market clearing prices for Energy, Operating Reserves, and Real-Time Market Prices for Regulation Service, and establish real-time schedules for those products on a five-minute basis, starting at the beginning of each hour. The Real-Time Dispatch will not make commitment decisions and will not consider start-up costs in any of its dispatching or pricing decisions, except as specifically provided in Section 4.4.2.4 below. In each interval, Real-Time Dispatch will review the Beginning Energy Level of each Energy Storage Resource and of each Aggregation comprised only of Energy Storage Resources.

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

Resource's Beginning Energy Level will be used to ensure that Operating Reserves scheduled from the Resource can be sustained for one hour if the Operating Reserves are converted to Energy. The Real-Time Dispatch will account for the CSR Scheduling Limits in the schedules and dispatch instructions it issues to CSR Generators.

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

#### 4.4.2.2 External Transaction Scheduling

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

#### 4.4.2.3 Calculating Real-Time Market LBMPs and Advisory Prices

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

LBMPs for the next four quarter hours in accordance with the procedures set forth in Attachment B.

#### 4.4.2.4 Real-Time Pricing Rules for Scheduling Ten Minute Resources

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

#### 4.4.2.5 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 4.4.2.5, will be eligible for a Day-Ahead Margin Assurance Payment, pursuant to Attachment J of this ISO Services Tariff.

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

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

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

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

Capacity that was scheduled Day-Ahead as ancillary services or Energy as being provided by a Curtailment Services Provider.

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

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

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

#### 4.4.2.7 Post the Real-Time Schedule

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

of the Dispatch Day. The ISO shall conduct the real-time settlement based upon the real-time schedule determined in accordance with this Section.

### 4.4.3 Real-Time Dispatch - Corrective Action Mode

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

The ISO shall have discretion to determine which specific RTD-CAM mode should be activated in particular situations. In addition, RTD-CAM may require Resources to run above their $UOL_N$s, up to the level of their $UOL_E$s as is described in the ISO Procedures. Self-Committed Fixed Resources will not be expected to move in response to RTD-CAM Base Point Signals except when a maximum generation pickup is activated. Combined Cycle Gas Turbine Generators with Duct-Firing Capability that have opted for the Limiting Participation Flag will not be dispatched beyond the specified Participation Limit, unless such a Resource is already at or above its Participation Limit, in which case it will not be dispatched any higher or lower than its physical basepoint in effect at the time that RTD-CAM is activated.

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

#### 4.4.3.1 RTD-CAM Modes

##### 4.4.3.1.1 Reserve Pickup

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

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

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

#### 4.4.3.1.2 Maximum Generation Pickup

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

Security constraints will be obeyed to the extent possible. The ISO will continue to optimize for Energy and Operating Reserves, will recognize locational Operating Reserve requirements and Scarcity Reserve Requirements, but will set all Regulation Service schedules to zero.

#### 4.4.3.1.3 Base Points ASAP -- No Commitments

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

#### 4.4.3.1.4 Base Points ASAP -- Commit As Needed

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

#### 4.4.3.1.5 Re-Sequencing Mode

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

#### 4.4.3.2 Calculating Real-Time LBMPs

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

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

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

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

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

Notes:

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

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

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

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

## 15.3 Rate Schedule 3 - Payments for Regulation Service

This Rate Schedule applies to Suppliers that provide Regulation Service to the ISO. The following Resources are not eligible to provide Regulation Service: (1) Behind-the-Meter Net Generation Resources that are comprised of more than one generating unit and that are dispatched as a single aggregate unit, (2) Aggregations that are comprised of one or more generating units (unless each of those generating units use inverter-based energy storage technology), and (3) Aggregations of Demand Side Resources where at least one Demand Side Resource facilitates its Demand Reduction by utilizing a Local Generator (unless each Local Generator uses inverter-based energy storage technology). Transmission Customers will purchase Regulation Service from the ISO under the ISO OATT.

### 15.3.1 Obligations of the ISO and Suppliers

#### 15.3.1.1 The ISO shall:

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

(b) Provide RTD Base Point Signals and AGC Base Point Signals to Suppliers providing Regulation Service to direct their output;

(c) Establish criteria in the ISO Procedures that Suppliers must meet to qualify, or re-qualify, to supply Regulation Service;

(d) Establish minimum metering requirements and telecommunication capability required for a Supplier to be able to respond to AGC Base Point Signals and RTD Base Point Signals sent by the ISO;

(e) Select Suppliers to provide Regulation Service in the Day-Ahead Market and Real-Time Market and establish Regulation Service schedules, in MWs of Regulation Capacity, for each scheduled Regulation Supplier in the Day-Ahead and Real-Time Markets, as described in Section 15.3.2 of this Rate Schedule;

(f) Pay Suppliers for providing Regulation Service as described in this Rate Schedule;

(g) Monitor Suppliers' performance to ensure that they provide Regulation Service as required, as described in Section 15.3.3 of this Rate Schedule; and

(h) Take into account the speed and accuracy of regulation resources in determining reserve requirements for Regulation Service.

**15.3.1.2 Each Supplier shall:**

(a) Register with the ISO the Regulation Capacity its resources are qualified to bid in the Regulation Services market;

(b) Choose to opt in or out of the Limiting Participation Flag if the resource is a Combined Cycle Gas Turbine Generator with Duct-Firing Capability.

(c) Provide the ISO with the Resource's Regulation Capacity Response Rate and the Resource's Regulation Movement Response Rate;

(d) Offer only Resources that are; (i) ISO-Committed Flexible or Self-Committed Flexible, 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;

(e) Not use, contract to provide, or otherwise commit Regulation Capacity that is selected by the ISO to provide Regulation Service to provide Energy or Operating Reserves to a Balancing Authority other than the ISO;

(f) Pay any charges imposed under this Rate Schedule;

(g) Ensure that all of its Resources that are selected to provide Regulation Service comply with Base Point Signals issued by the ISO at all times pursuant to the ISO Procedures; and ensure that all of its Resources that are selected to provide Regulation Service comply with all criteria and ISO Procedures that apply to providing Regulation Service.

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

(a) The ISO shall select Suppliers in the Day-Ahead Market to provide Regulation Service for each hour in the following Dispatch Day and in the Real-Time Market to provide Regulation Service for each interval in the Dispatch Day, from those that have Bid to provide Regulation Service from Resources and that meet the qualification standards and criteria established in Section 15.3.1 of this Rate Schedule and in the ISO Procedures.

(b) In order to schedule Suppliers in the Day-Ahead Market to provide Regulation Service for each hour in the following Dispatch Day, the ISO shall use, as each Supplier's Regulation Service Bid price, the sum of: a) the Supplier's Day-Ahead Regulation Capacity Bid Price and b) the product of the Supplier's Day-Ahead Regulation Movement Bid Price and the applicable Regulation Movement Multiplier.

(c) In order to schedule Suppliers in the Real-Time Market to provide Regulation Service for each interval in the Dispatch Day the ISO shall use, as each Supplier's Regulation Service Bid price, the sum of: a) the Supplier's Real-Time Regulation Capacity Bid Price and b) the product of the Supplier's Real-Time Regulation Movement Bid Price and the applicable Regulation Movement Multiplier.

(d) The ISO shall establish separate Regulation Capacity Market Prices in the Day-Ahead Market and the Real-Time Market under Sections 15.3.4, 15.3.5 and 15.3.7 of this Rate Schedule and shall establish a Real-Time Regulation Movement Market Price under Section 15.3.5.1 of this Rate Schedule. The ISO shall also compute Regulation Revenue Adjustment Payments and Regulation Revenue Adjustment Charges under Section 15.3.6 of this Rate Schedule.

**15.3.2.1 Bidding Process**

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

(b) Bids rejected by the ISO may be modified and resubmitted by the Supplier to the ISO in accordance with the terms of the ISO Tariff.

(c) Each Bid shall contain the following information: (i) the maximum amount of capability (in MW) that the Resource is willing to provide as Regulation Capacity; (ii) the Supplier's Bid Price (in $/MW) for Regulation Capacity; and (iii) the Suppliers Bid Price (in $/MW) for Regulation Movement.

(d) Regulation Service Offers from Limited Energy Storage Resources: The ISO may reduce the real-time Regulation Capacity offer (in MWs) from a Limited Energy Storage Resource or an Aggregation of Limited Energy Storage Resources to account for the Energy storage capacity of such Resource.

(e) Regulation Service Offers from Energy Storage Resources: The ISO may reduce the real-time Regulation Capacity (in MW) from an Energy Storage Resource or an Aggregation of Limited Energy Storage Resources to account for the Energy Level of such Resource.

(f) Regulation Service Offers from Combined Cycle Gas Turbine Generators with Duct-Firing Capability that have opted for the Limiting Participation Flag: The ISO shall limit the Regulation Capacity (in MW) from a Combined Cycle Gas Turbine Generator with Duct Firing Capability, that has opted for the Limiting Participation Flag, to the Resource's maximum Regulation Service capability without exceeding its Participation Limit.

### 15.3.3 Monitoring Regulation Service Performance and Performance Related Payment Adjustments

(a) The ISO shall establish (i) Resource performance measurement criteria; (ii) procedures to disqualify Suppliers whose Resources consistently fail to meet those criteria; and (iii) procedures to re-qualify disqualified Suppliers, which may include a requirement to first demonstrate acceptable performance for a time.

(b) The ISO shall establish and implement a Performance Tracking System to monitor the performance of Suppliers that provide Regulation Service. The ISO shall develop performance indices, which may vary with Control Performance, as part of the ISO Procedures. The ISO shall use the values provided by the

Performance Tracking System to adjust settlements for real-time Regulation Movement pursuant to Section 15.3.5.4.1 and to compute a performance charge to apply to real-time Regulation Service providers pursuant to Section 15.3.5.4.2 of this Rate Schedule.

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

### 15.3.4 Regulation Service Settlements - Day-Ahead Market

#### 15.3.4.1 Calculation of Day-Ahead Market Prices

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

would lead to it being scheduled to provide (or for a Withdrawal-Eligible Generator to withdraw) less Energy or to provide less Operating Reserves (or the applicable price on the Regulation Service Demand Curve during shortage conditions). Shadow Prices consistent with the Regulation Service Demand Curves described in Section 15.3.7 of this Rate Schedule will ensure that Regulation Service is not scheduled by SCUC at a cost greater than the Regulation Service Demand Curve.

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

#### 15.3.4.2 Other Day-Ahead Payments

A Supplier that bids on behalf of a Generator or Aggregation that provides Regulation Service may be eligible for a Day-Ahead Bid Production Cost guarantee payment pursuant to Section 4.6.6 and Attachment C of this ISO Services Tariff.

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

### 15.3.5 Regulation Service Settlements - Real-Time Market

#### 15.3.5.1 Calculation of Real-Time Market Prices

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

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

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

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

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

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

(a) When the Supplier's real-time Regulation Capacity schedule is less than its Day-Ahead Regulation Capacity schedule, the Supplier shall pay a charge for the imbalance equal to the product of: (i) the Real-Time Regulation Capacity Market Price; and (ii) the difference between the Supplier's Day-Ahead Regulation Capacity schedule and its real-time Regulation Capacity schedule.

(b) When the Supplier's real-time Regulation Capacity schedule is greater than its Day-Ahead Regulation Capacity schedule, the ISO shall pay the Supplier an amount to compensate it for the imbalance equal to the product of: (i) the Real-Time Regulation Capacity Market Price; and (ii) the difference between the Supplier's real-time Regulation Capacity schedule and its Day-Ahead Regulation Capacity schedule.

(c) The ISO shall pay Suppliers with real-time Regulation Capacity schedules a real-time payment for Regulation Movement provided in each interval. The payment amount shall equal the product of: (a) the Real-Time Regulation Movement Market Price in that interval; (b) the Regulation Movement instructed during the interval, and (c) the performance factor calculated for that Regulation Service provider in that interval pursuant to Section 15.3.5.4.1.

(d) The ISO shall assess a performance charge, pursuant to Section 15.3.5.4.2 to all Suppliers of Regulation Service with real-time Regulation Service schedules.

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

#### 15.3.5.3 Other Real-Time Regulation Service Payments

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

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

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

##### 15.3.5.4.1 Performance-Based Adjustment to Payments for Regulation Service Suppliers

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

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

Where:

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

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

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

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

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

**15.3.5.4.2 Performance-Based Charge to Suppliers of Regulation Service**

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

$$Performance\ Charge_i = \Big(\big((1 - K_{PIi}) * RTRinccap_i * \text{-}1.1 * RTMPreg_i\big) + \Big(\big((1 - K_{PIi}) * (RTRcap_i - RTRinccap_i) * \text{-}1.1\big) * Max\big(DAMPreg_, RTMPreg_i\big)\Big)\Big) * (S_i/3600)$$

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

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

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

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

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

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

## 15.3.6 Energy Settlement Rules for Suppliers Providing Regulation Service

### 15.3.6.1 Energy Settlements

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

B. Demand Reductions from Aggregations providing Regulation Service are only eligible for payment for Energy when the real-time LBMP, at the Aggregation's Transmission Node, meets or exceeds the Net Benefits Test Threshold calculated in accordance with Section 4.5.7 of the Services Tariff for the applicable period. When the Net Benefits Test Threshold is satisfied, such Aggregations shall receive an Energy payment for Demand Reductions equal to the lower of the Demand Reductions' contribution to the actual Energy provided or the Aggregation's AGC Base Point Signal.

C. For any hour in which a Limited Energy Storage Resource or Aggregation of Limited Energy Storage Resources has injected or withdrawn Energy, pursuant to

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

$$Energy\ Settlements_h = Net\ MWHR_h * LBMP_h$$

Where:

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

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

**15.3.6.2 Additional Payments/Charges**

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

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

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

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

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

Where:

$S$ = the number of seconds in the RTD interval;

If the result of the calculation is positive then the Supplier shall receive a RRAP. If it is negative then the Supplier shall be subject to a RRAC. For purposes of applying this formula, whenever the Supplier's actual Bid exceeds the applicable LBMP the "Bid" term shall be set at a level equal to the lesser of the Supplier's actual Bid or its reference Bid plus $100/MWh. 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 Supplier that is providing Regulation Service receives an AGC Base Point Signal that is lower than its RTD Base Point Signal, it shall receive or pay a RRAP or RRAC calculated under the terms of this subsection. If the Energy Bid Price of such a Supplier is higher than the LBMP at its location in that interval, the Supplier shall be assessed a RRAC. Conversely, for any interval in which such a Supplier's Energy Bid Price is lower than the LBMP at its location in that interval, the Supplier shall receive a RRAP. RRAPs and RRACs shall be calculated using the following formula:

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

Where:

*S* = the number of seconds in the RTD interval;

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

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

### 15.3.7 Regulation Service Demand Curve

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

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

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

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

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

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

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

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

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

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

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

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

## 15.4 Rate Schedule 4 - Payments for Supplying Operating Reserves

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

### 15.4.1 General Responsibilities and Requirements

#### 15.4.1.1 ISO Responsibilities

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

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

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

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

with the additive market clearing price calculation formulae in Sections 15.4.5.1 and 15.4.6.1 of this Rate Schedule).

#### 15.4.1.2 Supplier Eligibility Criteria

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

##### 15.4.1.2.1 Spinning Reserve:

Suppliers that are ISO Committed Flexible or Self-Committed Flexible, are operating within the dispatchable portion of their operating range, are capable of responding to ISO instructions to change their output level within ten minutes, and that meet the criteria set forth in the ISO Procedures shall be eligible to supply Spinning Reserve (except for Demand Side Resources that are Local Generators not utilizing inverter-based energy storage technology). The following types of resources are only eligible to provide Spinning Reserve if all of the generating units use inverter-based energy storage technology and meet the criteria set forth in the ISO Procedures: (a) Aggregations comprised of one or more generating units, (b) Aggregations that include Demand Side Resource(s) where at least one Demand Side Resource facilitates its Demand Reduction by utilizing a Local Generator, and (c) Behind-the-Meter Net Generation Resources that are comprised of more than one generating unit and dispatched as a single aggregate unit. Suppliers utilizing inverter-based energy storage technology, and that meet the criteria set forth in the ISO Procedures, shall be eligible to supply Spinning Reserve when withdrawing or injecting Energy, and when idle.

**15.4.1.2.2 10-Minute Non-Synchronized Reserve:**

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

**15.4.1.2.3 30-Minute Reserve:**

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

Meter Net Generation Resources that are comprised of more than one generating unit and dispatched as a single aggregate unit that are capable of increasing their output level within thirty (30) minutes; and (iv) Demand Side Resources that are capable of reducing their Energy usage/Aggregations comprised of one or more generating units that are capable of increasing their output level within thirty (30) minutes, that meet the criteria set forth in the ISO Procedures shall be eligible to supply non-synchronized 30-Minute Reserves.

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

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

### 15.4.1.3 Other Supplier Requirements

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

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

Suppliers that are selected to provide Operating Reserve in the Day-Ahead Market may increase their Incremental Energy Bids or Demand Reduction Bids, respectively, for portions of their Resources that have been scheduled; provided however, that they are not otherwise prohibited from doing so pursuant to other provisions of the ISO's Tariffs. Withdrawal-Eligible Generators or Aggregations comprised of one or more Withdrawal-Eligible Generators that are

scheduled to withdraw Energy, and that are selected to provide Operating Reserve in the Day-Ahead Market, may decrease their Bids to withdraw Energy for portions of their resources that have been scheduled through those processes; provided that they are not otherwise prohibited from doing so pursuant to other provisions of the ISO's Tariffs. Suppliers that are selected to provide Operating Reserve in the Day-Ahead Market may not reduce the $UOL_N$ in their Real-Time Market Bids below the sum of their Day-Ahead Market schedules for Energy, Operating Reserve, and Regulation Service, except to the extent that they are directed to do so by the ISO. The ISO may reduce the real-time Operating Reserve schedule (in MW) from an Energy Storage Resource to account for the Energy Level of such Resource, as discussed in Section 4.4.2.1 of this ISO Services Tariff. Suppliers may enter into alternate sales arrangements utilizing any Capacity that has not been scheduled to provide Operating Reserve.

### 15.4.2 General Day-Ahead Market Rules

#### 15.4.2.1 Bidding and Bid Selection

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

The ISO may schedule Suppliers that make themselves available to provide Operating Reserves up to the following maximum Operating Reserve levels: (i) for Spinning Reserves, the least of the Resource's emergency response rate multiplied by ten, or the Resource's applicable Upper Operating Limit (*i.e.,* $UOL_N$, $UOL_E$); (ii) for 10-Minute Non-Synchronized Reserves, or

for non-synchronized 30-Minute Reserves, the Resource's 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 least of the Resource's emergency response rate multiplied by twenty and its applicable Upper Operating Limit. The ISO may schedule a Combined Cycle Gas Turbine Generator with Duct-Firing Capability that has opted for the Limiting Participation Flag, which is available to provide Operating Reserves, up to the following maximum Operating Reserve levels: (i) for Spinning Reserves, the least of the Resource's emergency response rate multiplied by ten, or the Resource's applicable Participation Limit; and (ii) for synchronized 30-Minute Reserves, the least of the Resource's emergency response rate multiplied by twenty and its applicable Upper Operating Limit.

However, the sum of the amount of Energy or Demand Reduction a Resource is scheduled to provide, the amount of Regulation Service it is scheduled to provide, and the amount of each Operating Reserves product it is scheduled to provide shall not exceed its UOLN or UOLE, whichever is applicable. For an Energy Storage Resource or an Aggregation of Energy Storage Resources, the Resource's Energy schedule minus its Regulation Service schedule shall not be less than the Resource's Lower Operating Limit.

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

For Co-located Storage Resources the sum of the amount of Energy each Generator is scheduled to provide, the amount of Regulation Service the Energy Storage Resource and any

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

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

#### 15.4.2.2 ISO Notice Requirement

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

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

Suppliers that are scheduled Day-Ahead to provide Operating Reserves shall either provide Operating Reserve, Energy or Demand Reductions in real-time when scheduled by the ISO in all hours for which they have been selected to provide Operating Reserve and are physically capable of doing so. However, Suppliers that are scheduled Day-Ahead to provide

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

### 15.4.3 General Real-Time Market Rules

#### 15.4.3.1 Bid Selection

The ISO will automatically select Operating Reserves Suppliers in real-time from eligible Resources, that submit Real-Time Bids pursuant to Section 4.4 of, and Attachment D to, this ISO Services Tariff. Each Supplier will automatically be assigned a real-time Operating Reserves Availability bid of $0/MW for the quantity of Capacity that it makes available to the ISO in its Real-Time Bid. The ISO may schedule Suppliers that make themselves available to provide Operating Reserves up to the following maximum Operating Reserve levels: (i) for Spinning Reserves, the least of the Resource's emergency response rate multiplied by ten and the Resource's applicable Upper Operating Limit ($UOL_N$ or $UOL_E$); (ii) for 10-Minute Non-Synchronized Reserves, or for non-synchronized 30-Minute Reserves, the Resource's $UOL_N$ or $UOL_E$, whichever is applicable at the relevant time (the Resource may offer one product or the other depending on the time required for it to start-up and synchronize to the grid); and (iii) for synchronized 30-Minute Reserves, the least of the Resource's emergency response rate multiplied by twenty and the Resource's applicable Upper Operating Limit ($UOL_N$ or $UOL_E$).

The ISO may schedule a Combined Cycle Gas Turbine Generator with Duct-Firing Capability that has opted for the Limiting Participation Flag, which is available to provide Operating Reserves, up to the following maximum Operating Reserve levels: (i) for Spinning Reserves, the least of the Resource's emergency response rate multiplied by ten, or the Resource's applicable Participation Limit; and (ii) for synchronized 30-Minute Reserves, the least of the Resource's emergency response rate multiplied by twenty and its applicable Upper Operating Limit.

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

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

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

of Regulation Service the Energy Storage Resource and any other participating Generator that is eligible to provide Regulation Service are scheduled to provide, shall account for the CSR withdrawal Scheduling Limit consistent with ISO Procedures.

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

#### 15.4.3.2 ISO Notice Requirement

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

#### 15.4.3.3 Obligation to Make Resources Available to Provide Operating Reserves

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

#### 15.4.3.4 Activation of Operating Reserves

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

#### 15.4.3.5 Performance Tracking and Supplier Disqualifications

When a Supplier committed to supply Operating Reserves is activated, the ISO shall measure and track its actual Energy injections, withdrawals, and Demand Reductions against its

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

### 15.4.4 Operating Reserves Settlements - General Rules

#### 15.4.4.1 Establishing Locational Reserve and Scarcity Reserve Requirement Prices

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

#### 15.4.4.2 Settlements Involving Suppliers of Operating Reserves Located on Long Island

Suppliers of Operating Reserves located on Long Island shall receive settlement payments as if they were providing Operating Reserves located in Southeastern New York,

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

#### 15.4.4.3 "Cascading" of Operating Reserves

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

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

### 15.4.5 Operating Reserve Settlements – Day-Ahead Market

#### 15.4.5.1 Calculation of Day-Ahead Market Clearing Prices

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

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

Market clearing price for Western 30-Minute Reserves = SP1

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Where:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

particular quality than is needed is scheduled to meet a particular locational Operating Reserve requirement, the Shadow Price for that Operating Reserve requirement constraint shall be set at zero.

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

#### 15.4.5.2 Other Day-Ahead Payments

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

### 15.4.6 Operating Reserve Settlements – Real-Time Market

#### 15.4.6.1 Calculation of Real-Time Market Clearing Prices

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

The Real-Time Market clearing price for a particular Operating Reserve product for a particular location or Scarcity Reserve Region shall reflect the Shadow Prices associated with all of the ISO-defined Operating Reserve requirements, including locational requirements and

Scarcity Reserve Requirements, that a particular Operating Reserves product from that location or Scarcity Reserve Region may be used to satisfy in a given interval. The ISO shall calculate the Real-Time Market clearing prices using the following formulae:

Market clearing price for Western 30-Minute Reserves = SP1

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Where:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Real-time locational and Scarcity Reserve Requirement Shadow Prices will be calculated by the ISO's RTD. Each Real-Time Shadow Price for each Operating Reserves requirement,

including a Scarcity Reserve Requirement, in each RTD interval shall equal the marginal Bid cost of scheduling Resources to provide additional Operating Reserves to meet that requirement in that interval, including any impact on the Bid Production Cost of procuring Energy or Regulation Service that would result from procuring an increment of Operating Reserve to meet the requirement in that interval, as calculated during the second RTD pass described in Section 17.1.2.1.2.2 of Attachment B to this ISO Services Tariff. As a result, the Shadow Price for each Operating Reserves requirement, including a Scarcity Reserve Requirement, shall include the Real-Time Availability Bid of the marginal Resource selected to meet that requirement (or the applicable price on the Operating Reserve Demand Curve or Scarcity Reserve Demand Curve for that requirement during shortage conditions), plus any margins on the sale of Energy or Regulation Service in the Real-Time Market that that Resource would forego if scheduling it to provide additional Operating Reserve to meet that requirement would lead to it being scheduled to provide less Energy or Regulation Service. Shadow Prices will also be consistent with the Operating Reserve Demand Curves and Scarcity Reserve Demand Curve described in Section 15.4.7 of this Rate Schedule, which will ensure that Operating Reserves are not scheduled by RTC at a cost greater than the relevant Operating Reserve Demand Curve or Scarcity Reserve Demand Curve indicates should be paid. If there is more Operating Reserve of the required quality than is needed to meet a particular locational Operating Reserve requirement or Scarcity Reserve Requirement then the Shadow Price for that Operating Reserve requirement or Scarcity Reserve Requirement constraint shall be zero.

Each Supplier that is scheduled in real-time to provide Operating Reserve shall be paid the applicable Real-Time Market clearing price, based on its location and the quality of

Operating Reserve scheduled, multiplied by the amount of Operating Reserve that the Supplier is scheduled to provide in each interval that was not scheduled Day-Ahead.

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

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

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

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

for the Scarcity Reserve Requirement shall be SP4. SP4 shall be utilized in the same manner as described in the formulae above in calculating Real-Time Market clearing prices;

iii. If the Scarcity Reserve Requirement is for a Scarcity Reserve Region that includes Load Zones G, H, I, J, and K (*i.e.*, all Southeastern New York Load Zones), but does not include Load Zones A, B, C, D, E, or F, then the Shadow Price for the Scarcity Reserve Requirement shall be SP7. SP7 shall be utilized in the same manner as described in the formulae above in calculating Real-Time Market clearing prices;

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

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

(b) When the Load Zones included in the Scarcity Reserve Region are not identical to the Load Zones of an existing locational reserve region, the Shadow Price attributable to the Scarcity Reserve Requirement will be added to the applicable

Shadow Price for the 30-Minute Reserve requirement for the existing locational reserve region to which all of the Load Zones included in the Scarcity Reserve Region belong. The inclusion of the Scarcity Reserve Requirement Shadow Prices shall apply only to the Load Zones included as part of a Scarcity Reserve Region. The use of Scarcity Reserve Requirement Shadow Prices in calculating Real-Time Market clearing in such circumstances is as follows:

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

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

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

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

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

The applicable value of the Expected EDRP/SCR MW for each Load Zone included in a Scarcity Reserve Region to be used in calculating the Scarcity Reserve Requirement is dependent upon whether the Load reduction for a given interval is deemed voluntary or mandatory for purposes of calculating the Scarcity Reserve Requirement, as further described

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

#### 15.4.6.3 Operating Reserve Balancing Payments

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

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

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

#### 15.4.6.4 Other Real-Time Payments

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

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

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

### 15.4.7 Operating Reserve Demand Curves and Scarcity Reserve Demand Curve

The ISO shall establish Operating Reserve Demand Curves for each locational Operating Reserves requirement. Specifically, there shall be a demand curve for: (i) Total Spinning Reserves; (ii) Eastern, Southeastern, New York City, or Long Island Spinning Reserves; (iii)

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

Reserve Demand Curve will be applicable only during the real-time intervals that such a Scarcity Reserve Requirement has been established by the ISO.

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

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

The ISO will then define an Operating Reserves demand curve for that hour corresponding to each Operating Reserves requirement as follows:

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

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

City, or Long Island Spinning Reserves requirement that are less than or equal to the target level for that locational requirement, the price on the Eastern, Southeastern, New York City, or Long Island Spinning Reserves demand curve shall be $40/MW. For all other quantities, the price on the Eastern, Southeastern, New York City, or Long Island Spinning Reserves demand curve shall be $0/MW.

(c) Southeastern, New York City, or Long Island Spinning Reserves: For quantities of Operating Reserves meeting the Southeastern, New York City, or Long Island Spinning Reserves requirement that are less than or equal to the target level for that locational requirement, the price on the Southeastern, New York City, or Long Island Spinning Reserves demand curve shall be $40/MW. For all other quantities, the price on the Southeastern, New York City, or Long Island Spinning Reserves demand curve shall be $0/MW.

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

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

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

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

(h) Southeastern, New York City, or Long Island 10-Minute Reserves: For quantities of Operating Reserves meeting the Southeastern, New York City, or Long Island 10-minute reserves requirement that are less than or equal to the target level for that locational requirement, the price on the Southeastern, New York City, or Long Island 10-minute reserves demand curve shall be $40/MW. For all other quantities, the price on the Southeastern, New York City, or Long Island 10-Minute Reserves demand curve shall be $0/MW.

(i) New York City 10-Minute Reserves: For quantities of Operating Reserves meeting the New York City 10-minute reserves requirement that are less than or equal to the target level for that locational requirement, the price on the New York

City 10-minute reserves demand curve shall be $25/MW. For all other quantities, the price on the New York City 10-minute reserves demand curve shall be $0/MW.

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

(k) Total 30-Minute Reserves: For quantities of Operating Reserves meeting the total 30-Minute Reserves requirement that are less than or equal to the target level for that locational requirement minus 655 MW, the price on the total 30-Minute Reserves demand curve shall be $750/MW. For quantities of Operating Reserves meeting the total 30-Minute Reserves requirement that (i) are less than or equal to the target level for that locational requirement minus 600 MW, but (ii) exceed the target level for that locational requirement minus 655 MW, the price on the total 30-Minute Reserves demand curve shall be $625/MW. For quantities of Operating Reserves meeting the total 30-Minute Reserves requirement that (i) are less than or equal to the target level for that locational requirement minus 545 MW, but (ii) exceed the target level for that locational requirement minus 600 MW, the price on the total 30-Minute Reserves demand curve shall be $500/MW. For quantities of Operating Reserves meeting the total 30-Minute Reserves requirement that (i) are less than or equal to the target level for that locational requirement minus 490 MW, but (ii) exceed the target level for that locational

requirement minus 545 MW, the price on the total 30-Minute Reserves demand curve shall be $375/MW. For quantities of Operating Reserves meeting the total 30-Minute Reserves requirement that (i) are less than or equal to the target level for that locational requirement minus 435 MW, but (ii) exceed the target level for that locational requirement minus 490 MW, the price on the total 30-Minute Reserves demand curve shall be $300/MW. For quantities of Operating Reserves meeting the total 30-Minute Reserves requirement that (i) are less than or equal to the target level for that locational requirement minus 380 MW, but (ii) exceed the target level for that locational requirement minus 435 MW, the price on the total 30-Minute Reserves demand curve shall be $225/MW. For quantities of Operating Reserves meeting the total 30-Minute Reserves requirement that (i) are less than or equal to the target level for that locational requirement minus 325 MW, but (ii) exceed the target level for that locational requirement minus 380 MW, the price on the total 30-Minute Reserves demand curve shall be $175/MW. For quantities of Operating Reserves meeting the total 30-Minute Reserves requirement that (i) are less than or equal to the target level for that locational requirement minus 200 MW, but (ii) exceed the target level for that locational requirement minus 325 MW, the price on the total 30-Minute Reserves demand curve shall be $100/MW. For quantities of Operating Reserves meeting the total 30-Minute Reserves requirement that (i) are less than or equal to the target level for that locational requirement, but (ii) exceed the target level for that locational requirement minus 200 MW, the price on the total 30-Minute Reserves demand curve shall be $40/MW. For all other quantities, the price on the total 30-Minute

Reserves demand curve shall be $0/MW. However, the ISO will not schedule more total 30-Minute Reserves than the target level established for the requirement for that hour.

During each real-time interval that the ISO has established a Scarcity Reserve Requirement in the Real-Time Market for which the pricing rules established in Section 15.4.6.1.1(a)(i) of this Rate Schedule apply, the applicable Operating Reserves demand curve for total 30-Minute Reserves shall be as follows: For quantities of Operating Reserves meeting the total 30-Minute Reserves locational requirement target level plus the Scarcity Reserve Requirement ("NYCA scarcity target level") that are less than or equal to the NYCA scarcity target level minus an amount equal to the sum of 655 MW and the Scarcity Reserve Requirement, the price on the total 30-Minute Reserves demand curve shall be $750/MW. For quantities of Operating Reserves meeting the NYCA scarcity target level that (i) are less than or equal to the NYCA scarcity target level minus an amount equal to the sum of 600 MW and the Scarcity Reserve Requirement, but (ii) exceed the NYCA scarcity target level minus an amount equal to the sum of 655 MW and the Scarcity Reserve Requirement, the price on the total 30-Minute Reserves demand curve shall be $625/MW. For quantities of Operating Reserves meeting the NYCA scarcity target level that (i) are less than or equal to the NYCA scarcity target, but (ii) exceed the NYCA scarcity target level minus an amount equal to the sum of 600 MW and the Scarcity Reserve Requirement, the price on the total 30-Minute Reserves demand curve shall be $500/MW. For all other quantities, the price on the total 30-Minute Reserves demand curve shall be $0/MW.

However, the ISO will not schedule more total 30-Minute Reserves than the NYCA scarcity target level for that interval.

During each real-time interval that the ISO has established a Scarcity Reserve Requirement(s) in the Real-Time Market, other than a Scarcity Reserve Requirement for which the pricing rules established in Section 15.4.6.1.1(a)(i) of this Rate Schedule apply, the applicable Operating Reserves demand curve for total 30-Minute Reserves shall be as follows: For quantities of Operating Reserves meeting the total 30-Minute Reserves locational requirement target level plus the applicable Scarcity Reserve Requirement(s) ("adjusted NYCA target level") that are less than or equal to the adjusted NYCA target level minus an amount equal to the sum of 655 MW and the Scarcity Reserve Requirement(s), the price on the total 30-Minute Reserves demand curve shall be $750/MW. For quantities of Operating Reserves meeting the adjusted NYCA target level that (i) are less than or equal to the adjusted NYCA target level minus an amount equal to the sum of 600 MW and the Scarcity Reserve Requirement(s), but (ii) exceed the adjusted NYCA target level minus an amount equal to the sum of 655 MW and the Scarcity Reserve Requirement(s), the price on the total 30-Minute Reserves demand curve shall be $625/MW. For quantities of Operating Reserves meeting the adjusted NYCA target level that (i) are less than or equal to the adjusted NYCA target level, but (ii) exceed the adjusted NYCA target level minus an amount equal to the sum of 600 MW and the Scarcity Reserve Requirement(s), the price on the total 30-Minute Reserves demand curve shall be $500/MW. For all other quantities, the price on the total 30-Minute Reserves demand curve shall

be $0/MW. However, the ISO will not schedule more total 30-Minute Reserves than the adjusted NYCA target level for that interval.

(l) Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves: For quantities of Operating Reserves meeting the Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves requirement that are less than or equal to the target level for that locational requirement, the price on the Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be $40/MW. For all other quantities, the price on the Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be $0/MW.

During each real-time interval that the ISO has established a Scarcity Reserve Requirement in the Real-Time Market for which the pricing rules established in Section 15.4.6.1.1(a)(ii) of this Rate Schedule apply, the applicable Operating Reserves demand curve for Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves shall be as follows: For quantities of Operating Reserves meeting the Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves locational requirement target level plus the Scarcity Reserve Requirement ("Eastern scarcity target level") that are less than or equal to the Eastern scarcity target level minus an amount equal to the Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves locational requirement target , the price on the Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be $500/MW. For the quantities of Operating Reserves meeting the Eastern scarcity target level that (i) are less than

or equal to the Eastern scarcity target level , but (ii) exceed the Eastern scarcity target level minus an amount equal to the Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves locational requirement target level, the price on the Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be $40/MW. For all other quantities, the price on the Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be $0/MW.

During each real-time interval that the ISO has established a Scarcity Reserve Requirement(s) in the Real-Time Market for which all the Load Zones encompassed by such Scarcity Reserve Requirement belong to the East of Central-East reserve region, other than a Scarcity Reserve Requirement for which the pricing rules established in Section 15.4.6.1.1(a)(ii) of this Rate Schedule apply, the applicable Operating Reserves demand curve for Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves shall be as follows: For quantities of Operating Reserves meeting the Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves locational requirement target level plus the applicable Scarcity Reserve Requirement(s) (“adjusted Eastern target level”) that are less than or equal to the adjusted Eastern target level, the price on the Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be $40/MW. For all other quantities, the price on the Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be $0/MW.

(m) Southeastern, New York City, or Long Island 30-Minute Reserves: For quantities of Operating Reserves meeting the Southeastern, New York City, or Long Island 30-Minute Reserves requirement that are less than or equal to the target level for that locational requirement minus any incremental 30-Minute Reserve target level established by the ISO for an amount not to exceed 500 MW ("SENY incremental reserve target level"), the price on the Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be $500/MW. For quantities of Operating Reserves meeting the Southeastern, New York City, or Long Island 30-Minute Reserves requirement that (i) are less than or equal to the target level for that locational requirement, but (ii) exceed the target level for that locational requirement minus the SENY incremental reserve target level, the price on the Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be $40/MW. For all other quantities, the price on the Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be $0/MW. During each real-time interval that the ISO has established a Scarcity Reserve Requirement in the Real-Time Market for which the pricing rules established in Section 15.4.6.1.1(a)(iii) of this Rate Schedule apply, the applicable Operating Reserves demand curve for Southeastern, New York City, or Long Island 30-Minute Reserves shall be as follows: For quantities of Operating Reserves meeting the Southeastern, New York City, or Long Island 30-Minute Reserves locational requirement target level plus the Scarcity Reserve Requirement ("Southeastern scarcity target level") that are less than or equal to the Southeastern scarcity target level minus the SENY incremental reserve target

level, the price on the Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be $500/MW. For quantities of Operating Reserves meeting the Southeastern scarcity target level that (i) are less than or equal to the Southeastern scarcity target level, but (ii) exceed the Southeastern scarcity target level minus the SENY incremental reserve target level, the price on the Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be $40/MW. For all other quantities, the price on the Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be $0/MW. During each real-time interval that the ISO has established a Scarcity Reserve Requirement(s) in the Real-Time Market for which all the Load Zones encompassed by such Scarcity Reserve Requirement belong to the Southeastern New York reserve region, other than a Scarcity Reserve Requirement for which the pricing rules established in Section 15.4.6.1.1(a)(iii) of this Rate Schedule apply, the applicable Operating Reserves demand curve for Southeastern, New York City, or Long Island 30-Minute Reserves shall be as follows: For quantities of Operating Reserves meeting the Southeastern, New York City, or Long Island 30-Minute Reserves locational requirement target level plus the applicable Scarcity Reserve Requirement(s) ("adjusted Southeastern target level") that are less than or equal to the adjusted Southeastern target level minus the SENY incremental reserve target level, the price on the Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be $500/MW. For quantities of Operating Reserves meeting the adjusted Southeastern target level that (i) are less than or equal to the adjusted Southeastern target level, but (ii) exceed the

adjusted Southeastern target level minus the SENY incremental reserve target level, the price on the Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be $40/MW. For all other quantities, the price on the Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be $0/MW.

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

During each real-time interval that the ISO has established a Scarcity Reserve Requirement in the Real-Time Market for which the pricing rules established in Section 15.4.6.1.1(a)(iv) of this Rate Schedule apply, the applicable Operating Reserves demand curve for New York City 30-Minute Reserves shall be as follows: For quantities of Operating Reserves meeting the New York City 30-Minute Reserves locational requirement target level plus the Scarcity Reserve Requirement ("N.Y.C. scarcity target level") that are less than or equal to the N.Y.C. scarcity target level minus an amount equal to the New York City 30-Minute Reserves locational requirement target level, the price on the New York City 30-Minute Reserves demand curve shall be $500/MW. For the quantities of Operating Reserves meeting the N.Y.C. scarcity target level that (i) are less than or equal to the N.Y.C. scarcity target level, but (ii) exceed the N.Y.C. scarcity

target level minus an amount equal to the New York City 30-Minute Reserves locational requirement target level, the price on the New York City 30-Minute Reserves demand curve shall be $25/MW. For all other quantities, the price on the New York City 30-Minute Reserves demand curve shall be $0/MW.

(o) Long Island 30-Minute Reserves: For quantities of Operating Reserves meeting the Long Island 30-Minute Reserves requirement that are less than or equal to the target level for that locational requirement, the price on the Long Island 30-Minute Reserves demand curve shall be $25/MW. For all other quantities, the price on the Long Island 30-Minute Reserves demand curve shall be $0/MW. During each real-time interval that the ISO has established a Scarcity Reserve Requirement in the Real-Time Market for which the pricing rules established in Section 15.4.6.1.1(a)(v) of this Rate Schedule apply, the applicable Operating Reserves demand curve for Long Island 30-Minute Reserves shall be as follows: For quantities of Operating Reserves meeting the Long Island 30-Minute Reserves locational requirement target level plus the Scarcity Reserve Requirement ("Long Island scarcity target level") that are less than or equal to the Long Island scarcity target level minus an amount equal to the Long Island 30-Minute Reserves locational requirement target level, the price on the Long Island 30-Minute Reserves demand curve shall be $500/MW. For the quantities of Operating Reserves meeting the Long Island scarcity target level that (i) are less than or equal to the Long Island scarcity target level, but (ii) exceed the Long Island scarcity target level minus an amount equal to the Long Island 30-Minute Reserves locational requirement target level, the price on the Long Island 30-

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

The ISO will procure additional Operating Reserves to meet each Scarcity Reserve Requirement established by the ISO in the Real-Time Market for which the pricing rules established in Section 15.4.6.1.1(b) of this Rate Schedule apply. The Scarcity Reserve Demand Curve for each real-time interval in which the ISO has established such a Scarcity Reserve Requirement shall be defined as follows: For quantities of Operating Reserves meeting the Scarcity Reserve Requirement that are less than or equal to the Scarcity Reserve Requirement, the price on the Scarcity Reserve Demand Curve shall be $500/MW. For all other quantities, the price on the Scarcity Reserve Demand Curve shall be $0/MW.

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

If the ISO determines that it is necessary to modify the quantity and/or price points specified above in order to avoid future operational or reliability problems it may temporarily modify them for a period of up to ninety days. If circumstances reasonably allow, the ISO will consult with its Market Monitoring Unit, the Business Issues Committee, the Commission, and

the PSC before implementing any such modification. In all circumstances, the ISO will consult with those entities as soon as reasonably possible after implementing a temporary modification.

Not later than 90 days after the implementation of the Operating Reserves Demand Curves the ISO, in consultation with its Market Advisor, shall conduct an initial review of them in accordance with the ISO Procedures. The scope of the review shall include, but not be limited to, an analysis of whether any Operating Reserve Demand Curve should be adjusted upward or downward in order to optimize the economic efficiency of any, or all, of the ISO Administered Markets. The ISO and the Market Advisor shall perform additional quarterly reviews, subject to the same scope requirement, during the remainder of the first year that this Section 15.4.7 is in effect. After the first year, the ISO shall perform periodic reviews, subject to the same scope requirement, and the Market Monitoring Unit shall be given the opportunity to review and comment on the ISO's periodic reviews of the Operating Reserve Demand Curves and Scarcity Reserve Demand Curve.

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

**15.4.8 Self-Supply**

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

the market value of the services provided by the specified Generator(s) or Aggregation(s) as determined in the ISO Services Tariff.

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

## 17.1 LBMP Calculation

The Locational Based Marginal Prices ("LBMPs" or "prices") for Suppliers and Loads in the Real-Time Market will be based on the system marginal costs produced by the Real-Time Dispatch ("RTD") program and during intervals when certain conditions exist at Proxy Generator Buses, the Real-Time Commitment ("RTC") program. LBMPs for Suppliers and Loads in the Day-Ahead Market will be based on the system marginal costs produced by the Security Constrained Unit Commitment ("SCUC"). LBMPs calculated by SCUC and RTD will incorporate the incremental dispatch costs of Dispatchable Resources that would be scheduled to meet an increment of Load. For pricing purposes, the incremental dispatch costs of Fast-Start Resources that Bid ISO-Committed Flexible shall be adjusted to include start-up costs and minimum generation costs based on the Start-Up Bids and Minimum Generation Bids or mitigated Start-Up Bids and Minimum Generation Bids of each such Resource, as described in Section 17.1.1.2 below.

To the extent that tradeoffs exist between scheduling providers to produce Energy or reduce demand, and scheduling them to provide Regulation Service or Operating Reserves, LBMPs shall reflect the effect of meeting an increment of Load, given those tradeoffs, at each location on the Bid Production Cost associated with those services. As such, those LBMPs may incorporate: (i) Bids for Regulation Service or Operating Reserves; or (ii) shortage costs associated with the inability to meet a Regulation Service or Operating Reserves requirement under the Regulation Service Demand Curve set forth in Rate Schedule 3 of this ISO Services Tariff and Operating Reserve Demand Curves and Scarcity Reserve Demand Curve set forth in Rate Schedule 4 of this ISO Services Tariff. For the purposes of calculating LBMPs under this

Services Tariff Section 17, Energy withdrawals by Withdrawal-Eligible Generators are treated as negative generation, and can set price.

Additionally, for the purpose of calculating Real-Time LBMPs when RTD is committing and dispatching Resources meeting Minimum Generation Levels and capable of starting in ten minutes pursuant to Section 4.4.2.4 of this ISO Services Tariff, RTD shall include in the incremental dispatch cost of each such Resource a start-up cost based on the Start-Up Bid of each such Resource and shall assume for each such Resource a zero downward response rate.

### 17.1.1 LBMP Bus Calculation Method

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

The LBMP at bus i can be written as:

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

Where:

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

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

the equation:

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

Where:

| | | |
|---|---|---|
| $DF_i$ | = | delivery factor for bus *i* to the system Reference Bus and: |

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

Where:

$L$ = NYCA losses; and

$P_i$ = injection at bus *i*

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

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

Where:

$K$ = the set of Constraints;

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

$\mu_k$ = 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 $\gamma_i^L$ and $\gamma_i^C$ 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 Hopatcong-Ramapo interconnection based on the following:

a. The percentage of PJM-NYISO scheduled interchange that is expected to flow over the Hopatcong-Ramapo interconnection;

   1) The expected flow over the Hopatcong-Ramapo interconnection may also be adjusted by a MW offset to reflect expected operational conditions;

b. The percentage of PJM-NYISO scheduled interchange that is expected to flow over the ABC interface;

   1) The expected flow over the ABC interface will include an additional Operational Base Flow as described in Attachment CC to the OATT;

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

   1) The expected flow over the JK interface will include an additional Operational Base Flow as described in Attachment CC to the OATT.

The terms "ABC interface" and "JK interface" have the meaning ascribed to them in Attachment CC to the OATT.

The NYISO shall post the interchange percentage and Operational Base Flow values it is currently using to establish Day-Ahead and real-time expected Hopatcong-Ramapo interconnection, ABC interface and JK interface flows for purposes of scheduling and pricing on its web site. If the NYISO determines it is necessary to change the posted Hopatcong-Ramapo,

ABC or JK interchange percentage or Operational Base Flow values, it will provide notice to its Market Participants as far in advance of the change as is practicable under the circumstances.

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

For pricing purposes, flows in the Real-Time Market will be established for the ABC interface, JK interface, and Hopatcong-Ramapo interconnection based on the current flow, modified to reflect the expected incremental impacts of changes to interchange schedules over the forward scheduling horizon in a manner that is consistent with the method used to establish Day-Ahead power flows over these facilities. Expected flows over the NYISO's other interconnections will be determined based on the current flow, modified to reflect the expected incremental impacts of changes to interchange schedules over the forward scheduling horizon, and shall be consistent with shift factors and delivery factors calculated in accordance with Section 17.1.1.1, above.

**17.1.1.1.3 Scheduled Lines and Chateauguay Interconnection with Hydro Quebec**

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

#### 17.1.1.2 Incremental Dispatch Costs for Pricing Fast-Start Resources

For the purpose of calculating LBMPs for the Day-Ahead and Real-Time Markets, the incremental dispatch costs of Fast-Start Resources that Bid ISO-Committed Flexible shall be adjusted to include start-up costs and minimum generation costs based on the Start-Up Bids and Minimum Generation Bids or mitigated Start-Up Bids and Minimum Generation Bids of each such Resource ("Adjusted Dispatch Costs"). For start-up costs, the ISO will use a Fast-Start Resource's single point Start-Up Bid if one is submitted (or the mitigated Bid, where appropriate). If a Fast-Start Resource does not submit a single point Start-Up Bid in the Real-Time Market, the ISO will use the point on the Fast-Start Resource's multi-point Start-Up Bid curve (or its mitigated multi-point Start-Up Bid curve, where appropriate) that corresponds to the shortest specified down time.

The ISO will use the following procedure to determine a Fast-Start Resource's Adjusted Dispatch Costs for each pricing interval in the Day-Ahead and Real-Time Markets. The ISO will determine the "cost-minimizing output level" that minimizes the average as-Bid operating cost ("minimum average cost") for that Fast-Start Resource in each hour of the Day-Ahead Market and in each RTD interval of the Real-Time Market. The average as-Bid operating cost for a Fast-Start Resource at a given operating level shall include the Fast-Start Resource's minimum generation costs and incremental energy costs to provide Energy at that operating level, based on the Resource's Bids, or mitigated Bids as appropriate. The average as-Bid operating cost may also include some or all of the Fast-Start Resource's start-up costs based on the Resource's Bids, or mitigated Bids as appropriate, in a given hour, to be determined as follows: (1) for the Day-Ahead Market, a Fast-Start Resource's average as-Bid operating cost to operate in a given hour will include start-up costs for the hour the Resource is scheduled to start; or (2) for the Real-Time Market, a Fast-Start Resource's average as-Bid operating cost to operate in a given RTD

interval will include the start-up costs for approximately the first fifteen minutes, among consecutive operating intervals, after the Resource is scheduled to start, *i.e.*, for each RTD interval that starts within the first fifteen minutes after the Resource is scheduled to start, the average as-Bid operating cost to operate in that interval will include start-up costs.

For all output levels less than or equal to the cost-minimizing output level, the ISO will set the Adjusted Dispatch Cost equal to the minimum average cost. For all output levels greater than the cost-minimizing output level, the ISO will set the Adjusted Dispatch Cost equal to the price on the Resource's Bid curve. The ISO will calculate Adjusted Dispatch Costs for each output level between the Fast-Start Resource's minimum operating level and its $UOL_N$ or $UOL_E$ (whichever is applicable).

For the purpose of calculating LBMPs for the Day-Ahead and Real-Time Markets, all Fast-Start Resources that Bid ISO-Committed Flexible are treated as flexible and able to be dispatched anywhere between zero (0) MW and their $UOL_N$ or $UOL_E$ (whichever is applicable). The dispatch for Fast-Start Resources, including Fixed Block Units, that participate as Co-located Storage Resources will consider CSR Scheduling Limits.

Additional rules for Fixed Block Units are set forth below in Section 17.1.2.1.2.

### 17.1.2 Real-Time LBMP Calculation Procedures

For each RTD interval, the ISO shall use the procedures described below in Sections 17.1.2.1-17.1.2.1.4 to calculate Real-Time LBMPs at each Load Zone, Generator bus and Transmission Node. The LBMP bus and zonal calculation procedures are described in Sections 17.1.1 and 17.1.5 of this Attachment B, respectively. Procedures governing the calculation of LBMPs at Proxy Generator Buses are set forth below in Section 17.1.6 of this Attachment B.

#### 17.1.2.1 General Procedures

##### 17.1.2.1.1 Overview

The ISO shall calculate Real-Time Market LBMPs using the three passes of each RTD run, except as noted below in Section 17.1.2.1.3. A new RTD run will initialize every five minutes and each run will produce prices and schedules for five points in time (the optimization period). Only the prices and schedules determined for the first time point of the optimization period will be binding. Prices and schedules for the other four time points of the optimization period are advisory.

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

For example, the RTD run that posts its results at the beginning of an hour ("$RTD_0$") will initialize at the fifty-fifth minute of the previous hour and produce schedules and prices over a fifty-five minute optimization period. $RTD_0$ will produce binding prices and schedules for the RTD interval beginning when it posts its results (i.e., at the beginning of the hour) and ending at the first time point in its optimization period (i.e., five minutes after the hour). It will produce advisory prices and schedules for its second time point, which is ten minutes after the first time point in its optimization period, and advisory prices and schedules for its third, fourth and fifth time points, each of which would be fifteen minutes apart. The RTD run that posts its results at five minutes after the beginning of the hour ("$RTD_5$") will initialize at the beginning of the hour

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

#### 17.1.2.1.2 Description of the Real-Time Dispatch Process

##### 17.1.2.1.2.1 The First Pass

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

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

RTD will consider CSR Scheduling Limits when setting physical base points for Generators that participate as Co-located Storage Resources.

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

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

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

If it was not feasible for the Dispatchable Resource to reach that base point, then its upper and lower dispatch limits shall reflect the highest and lowest output levels it could achieve over the next RTD interval, subject to factors (A) through (E) specified above, but instead starting from the feasible output level closest to its previous base point.

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

The upper dispatch limit for a Dispatchable Resource at later time points shall be determined by adjusting the upper dispatch limit from the first time point at the Resource's response rate, up to its $UOL_N$ or $UOL_E$, whichever is applicable, considering Energy Level limitations for ISO-Managed ESRs. The lower dispatch limit for a Dispatchable Resource at later time points shall be determined by adjusting the lower dispatch limit from the first time point at the Resource's response rate, down to its minimum generation level/LOL considering applicable Energy Level limitations for ISO-Managed ESRs, or to a Demand Side Resource's Demand Reduction level.

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

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

For all time points of the optimization period, the Lower Dispatch Limit shall be the higher of (a) an Intermittent Power Resource's metered output level at the time that the RTD run

was initialized reduced by its response rate, or (b) zero. The Upper Dispatch Limit shall be the Wind and Solar Energy Forecast for that Resource. For Intermittent Power Resources depending on wind as their fuel in commercial operation as of January 1, 2002 with a name plate capacity of 12 MWs or fewer, the Upper and Lower Dispatch Limits shall be the output level specified by the Wind and Solar Energy Forecast.

**17.1.2.1.2.1.3. Setting Physical Basepoints for Fixed Generators and Aggregations**

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

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

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

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

commitment requests then its RTD Base Point Signals shall be determined using a response rate consistent with the operating schedule changes.

#### 17.1.2.1.2.2 The Second Pass

The second RTD pass consists of a least bid cost, multi-period, co-optimized dispatch for Energy, Regulation Service, and Operating Reserves that treats: (i) all Fast-Start Resources that are committed by RTC; (ii) Fixed Block Units that do not participate in a Co-located Storage Resource, are capable of starting and meeting Minimum Generation Levels in ten minutes, and have not been committed by RTC; and (iii) all Fixed Block Units otherwise instructed to be online or remain online by the ISO, as flexible (i.e., able to be dispatched anywhere between zero (0) MW and their $UOL_N$ or $UOL_E$, whichever is applicable), regardless of their minimum run-time status. The dispatch of Generators, including Fast-Start Resources and Fixed Block Units, that participate as Co-located Storage Resources will consider CSR Scheduling Limits. The second pass calculates real-time Energy prices and real-time Shadow Prices for Regulation Service and Operating Reserves that the ISO shall use for settlement purposes pursuant to Section 4, Rate Schedule 15.3, and Rate Schedule 15.4 of this ISO Services Tariff respectively. The ISO will not use schedules for Energy, Regulation Service and Operating Reserves established in the second pass to dispatch Resources.

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

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

The upper dispatch limit for the first time point of the second pass for a Dispatchable Resource shall be the higher of: (A) its upper dispatch limit from the first pass; or (B) its "pricing

base point" from the first time point of the prior RTD interval adjusted up within its Dispatchable range for any possible ramping since that pricing base point was issued less the higher of: (i) the physical base point established during the first pass of the RTD immediately prior to the previous RTD minus the Resource's metered output level at the time that the current RTD run was initialized, or (ii) zero.

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

The upper dispatch limit for the later time points of the second pass for a Dispatchable Resource shall be determined by adjusting its upper dispatch limit from the first time point at the Resource's response rate, up to its $UOL_N$ or $UOL_E$, whichever is applicable, considering Energy Level limitations for ISO-Managed ESRs. The lower dispatch limit for the later time points of the second pass for a Dispatchable non-Fast-Start Resource shall be determined by adjusting its lower dispatch limit from the first time point at the Resource's response rate, down to its minimum generation level/LOL, considering Energy Level limitations for ISO-Managed ESRs. The lower dispatch limit for the later time points of the second pass for a Fast Start Resource shall be determined by decreasing its lower dispatch limit from the first time point at the Resource's response rate, down to zero.

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

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

#### 17.1.2.1.2.3 The Third Pass

The third RTD pass is reserved for future use.

### 17.1.2.1.3 Variations in RTD-CAM

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

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

Second, if the ISO enters maximum generation pickup mode: (i) the ISO will produce prices and schedules for a single five minute interval (not for a multi-point co-optimization period); (ii) the ISO shall set Regulation Service schedules to zero as described in Rate Schedule

15.3 of this ISO Services Tariff; (iii) the ISO will have discretion to make additional Generator and Aggregation commitments in the affected area before executing the three RTD passes; and (iv) the ISO will have discretion: (a) either to move the RTD Base Point Signal of each Generator and Aggregation within the affected area towards its $UOL_E$ at its emergency response rate or set it at a level equal to its physical base point; (b) either to move the RTD Base Point Signal of each Combined Cycle Gas Turbine Generator with Duct-Firing Capability within the affected area, that has not opted for the Limiting Participation Flag, towards its $UOL_E$ at the normal response rate corresponding to its physical base point at the time when RTD-CAM was activated, or to set it at a level equal to that physical base point; and (c) either to move the RTD Base Point Signal of each Combined Cycle Gas Turbine Generator with Duct-Firing Capability within the affected area, that has opted for the Limiting Participation Flag, (1) towards its Participation Limit at the normal response rate corresponding to its physical base point at the time when RTD-CAM was activated, if the Generator's output level at that time is below the Participation Limit or (2) set it at a level equal to its physical base point at the time when RTD-CAM was activated, if Generator's output level at that time is equal to or above the Participation Limit.

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

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

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

**17.1.2.1.4 The Real-Time Commitment ("RTC") Process and Automated Mitigation**

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

In situations where Attachment H specifies that real-time automated mitigation measures be utilized, the ISO will perform the two parallel RTC evaluations in a manner that enables it to implement mitigation measures one RTC run (i.e., fifteen minutes) in the future. For example, $RTC_{15}$ and $RT\text{-}AMP_{15}$ will perform Resource commitment evaluations simultaneously. $RT\text{-}AMP_{15}$ will then apply the mitigation "impact" test, account for reference bid levels as appropriate and determine which Resources are actually to be mitigated. This information will then be conveyed to $RTC_{30}$ which will make Resource commitments consistent with the

application of the mitigation measures (and will thus indirectly be incorporated into future RTD runs).

### 17.1.3 Day-Ahead LBMP Calculation Procedures

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

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

It consists of several steps. Step 1A is a complete Security Constrained Unit Commitment ("SCUC") to meet Bid Load. At the end of this step, committed Fast-Start Resources, Imports, Exports, Virtual Supply, Virtual Load, Demand Side Resources and non-Fast-Start Resources are dispatched to meet Bid Load. Fast-Start Resources are treated as dispatchable between zero MW and their $UOL_N$ or $UOL_E$, whichever is applicable. For mitigation purposes, LBMPs are calculated from this dispatch. Following Step 1A, SCUC tests for automated mitigation procedure ("AMP") activation.

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

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

In Step 1C, generation offer prices subject to mitigation that exceed the conduct threshold are mitigated for those hours and zones in which the impact test was met in Step 1B. The mitigated offer prices, together with the original unmitigated offer price of units whose offer prices were not subject to mitigation, or did not trigger the conduct or impact thresholds, are used to commit generation and dispatch energy to meet Bid Load. This step is also a complete iteration of the SCUC process. At the end of Step 1C, committed Fast-Start Resources, Imports, Exports, virtual supply, virtual load, Demand Side Resources, and non- Fast-Start Resources are again dispatched to meet Bid Load. Fast-Start Resources are treated as dispatchable between zero MW and their $UOL_N$ or $UOL_E$, whichever is applicable. The dispatch for Generators, including Fast-Start Resources and Fixed Block Units, that participate as Co-located Storage Resources will consider CSR Scheduling Limits. For mitigation purposes, LBMPs are again calculated from this dispatch.

All Demand Side and non-Fast-Start Resources committed in the final step of Pass 1 (which could be either step 1A, 1B, or 1C depending on activation of the AMP) are blocked on at least to minimum generation level in Passes 4 through 6. All Energy Storage Resources and Aggregations dispatched in the final step of Pass 1 (which could be either Step 1A, 1B, or 1C depending on activation of the AMP) are blocked on at the dispatch that was determined in Pass 1 in Passes 2 through 4. The resources required to meet local system reliability are determined in Pass 1.

Pass 2 consists of a least cost commitment and dispatch of Fast-Start Resources, Imports, Exports, Demand Side Resources and non- Fast-Start Resources to meet forecast Load requirements in excess of Bid Load, considering the Wind and Solar Energy Forecast, that minimizes the cost of incremental Minimum Generation and Start Up Bids, given revenues for Minimum Generation Energy based on LBMPs calculated in Pass 1, and assumes all Fast-Start Resources are dispatchable between zero MW and their $UOL_N$ or $UOL_E$, whichever is applicable. The dispatch for Generators, including Fast-Start Resources, that participate as Co-located Storage Resources will consider CSR Scheduling Limits. Incremental Import Capacity needed to meet forecast Load requirements is determined in Pass 2. Fixed Block Units committed in this pass are not included in the least cost dispatches of Passes 5 or 6. Demand Side Resources and non-Fast-Start Resources committed in this step are blocked on at least to minimum generation level in Passes 4 through 6. Intermittent Power Resources that depend on wind or solar energy as their fuel committed in this pass as a result of the consideration of the Wind and Solar Energy Forecast are not blocked in Passes 5 or 6.

Pass 3 is reserved for future use.

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

Pass 5 consists of a least cost dispatch of Fast-Start Resources, Imports, Exports, Virtual Supply, Virtual Load, Demand Side Resources and non- Fast-Start Resources committed to meet Bid Load, based where appropriate on offer prices as mitigated in Pass 1. Fast-Start Resources

are treated as dispatchable between zero MW and their $UOL_N$ or $UOL_E$, whichever is applicable. LBMPs used to settle the Day-Ahead Market are calculated from this dispatch. The Shadow Prices used to compute Day-Ahead Market clearing prices for Regulation Service and for Operating Reserves in Rate Schedules 3 and 4 of this ISO Services Tariff are also calculated from this dispatch. Final schedules for all Imports, Exports, Virtual Supply, Virtual Load, Demand Side Resources and non-Fast-Start Resources in the Day-Ahead Market are calculated from this dispatch.

Pass 6 consists of a least cost dispatch of all Day-Ahead committed Resources, Imports, Exports, Virtual Supply, Virtual Load, based where appropriate on offer prices as mitigated in Pass 1, with the schedules of all Fixed Block Units committed in the final step of Pass 1 blocked on at maximum Capacity. Final schedules for Fast-Start Resources in the Day-Ahead Market are calculated from this dispatch.

### 17.1.4 Determination of Transmission Shortage Cost

The applicable Transmission Shortage Cost depends on whether a particular transmission Constraint is associated with a transmission facility or Interface that includes a non-zero constraint reliability margin value. The ISO shall establish constraint reliability margin values for transmission facilities and Interfaces. Non-zero constraint reliability margin values established by the ISO are normally equal to 20 MW. The ISO assigns a non-zero constraint reliability margin value (normally equal to 5 MW) to certain transmission facilities accommodating power flows out of export constrained areas (or "generation pockets") that, as further described below, are subject to a different Transmission Shortage Cost (for purposes of this Section 17.1.4, the aforementioned facilities are hereinafter referred to as "Identified Facilities"). The ISO shall post to its website a list of transmission facilities and Interfaces

assigned a constraint reliability margin value other than 20 MW. The list posted by the ISO shall also include Identified Facilities and the applicable constraint reliability margin value assigned to each such facility.

Except for Identified Facilities, when evaluating transmission Constraints associated with transmission facilities and Interfaces assigned a non-zero constraint reliability margin value, SCUC, RTC, and RTD shall include consideration of a six-step demand curve consisting of the following components: (1) a MW value of additional available resource capacity equal to or less than 20% of the applicable constraint reliability margin value, at a cost of $200/MWh; (2) a MW value of additional available resource capacity equal to or less than 40% of the applicable constraint reliability margin value, but greater than 20% of such value, at a cost of $350/MWh; (3) a MW value of additional available resource capacity equal to or less than 60% of the applicable constraint reliability margin value, but greater than 40% of such value, at a cost of $600/MWh; (4) a MW value of additional available resource capacity equal to or less than 80% of the applicable constraint reliability margin value, but greater than 60% of such value, at a cost of $1,500/MWh; (5) a MW value of additional available resource capacity equal to or less than 100% of the applicable constraint reliability margin value, but greater than 80% of such value, at a cost of $2,500/MWh; and (6) any MW value of additional available resource capacity greater than the applicable constraint reliability margin value, at a cost of $4,000/MWh.

When evaluating transmission Constraints associated with Identified Facilities, SCUC, RTC, and RTD shall include consideration of a two-step demand curve consisting of the following components: (1) a MW value of additional available resource capacity equal to or less than the applicable constraint reliability margin value, at a cost of $100/MWh; and (2) any MW

value of additional available resource capacity greater than the applicable constraint reliability margin value, at a cost of $250/MWh.

For transmission facilities and Interfaces assigned a non-zero constraint reliability margin value, the applicable demand curve, as described above, shall be applied in a manner such that it is considered in resolving, collectively, all applicable transmission Constraints associated with a particular transmission facility or Interface rather than applying a distinct demand curve individually to each such transmission Constraint. In the event of redundant transmission Constraints on in-series transmission facilities or parallel transmission facilities, the most limiting of such redundant transmission Constraints shall be deemed binding and utilized for the purposes of determining the applicable Shadow Price for the redundant transmission Constraints at issue. The less limiting of such redundant transmission Constraints on in-series transmission facilities or parallel transmission facilities shall be deemed non-binding and assigned a zero value Shadow Price. The MW value of the additional available resource capacity associated with each step of the applicable demand curve, as described above, shall be rounded to the nearest whole number.

For transmission facilities and Interfaces with a constraint reliability margin value of zero, the Shadow Price for transmission Constraints associated with such facilities and Interfaces shall not exceed $4,000/MWh. SCUC, RTC, and RTD shall not include consideration of additional available resource capacity provided by a demand curve mechanism for such transmission Constraints.

In evaluating transmission Constraints for transmission facilities and Interfaces with a constraint reliability margin value of zero, the ISO will determine whether sufficient available resource capacity exists to solve each transmission Constraint at its applicable limit. If sufficient

available resource capacity does not exist to solve the transmission Constraint at its otherwise applicable limit, the ISO shall increase the applicable limit for such transmission Constraint to an amount achievable by the available resource capacity plus 0.2 MW.

Notwithstanding anything to the contrary herein, in circumstances where the ISO is the "Non-Monitoring RTO" with respect to a transmission Constraint associated with a "Flowgate" subject to "M2M" coordination, the ISO's evaluation of such transmission Constraint in the Real-Time Market shall be consistent with the rules and procedures specified in Section 35.23 of Attachment CC of the ISO OATT. For purposes of this Section 17.1.4, the terms "Non-Monitoring RTO," "Flowgate," and "M2M" shall have the meaning specified in Section 35.2.1 of Attachment CC of the ISO OATT.

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

implementing a temporary modification and shall explain the reasons for the change; and (ii) notify Market Participants of any temporary modification.

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

### 17.1.5 Zonal LBMP Calculation Method

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

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

where:

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

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

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

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

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

#### 17.1.6.1 Definitions

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

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

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

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

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

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

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

#### 17.1.6.2 General Rules

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

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

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

#### 17.1.6.2.1 Pricing rules for Dynamically Scheduled Proxy Generator Buses

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

#### 17.1.6.2.2 Pricing rules for Variably Scheduled Proxy Generator Buses

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

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

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

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

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

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

Real-Time LBMPs for an Interface that is associated with one or more Non-Competitive Proxy Generator Buses or for a Non-Competitive Proxy Generator Bus shall be determined as

provided in the tables below. Non-Competitive Proxy Generator Buses are identified in Section 4.4.4 of the Services Tariff.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

| Rule No. | Proxy Generator Bus Constraint affecting External Schedules at location *a* | Direction of Proxy Generator Bus Constraint | Real-Time Pricing Rule (for location *a*) |
|---|---|---|---|
| 7 | $RTC_{15}$ is subject to an Interface ATC Constraint | Out of NYCA (Export) | If $RTC_{15}$ Proxy Generator Bus $LBMP_a < 0$, then Real-Time $LBMP_a$ = RTD $LBMP_a$ + $RTC_{15}$ External Interface $Congestion_a$<br><br>Otherwise, Real-Time $LBMP_a$ = RTD $LBMP_a$ |

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

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

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

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

and

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

where:

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

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