

Attachment I

2.2 Definitions - B

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

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

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

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

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

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

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

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

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

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

Bilateral Transaction: A Transaction between two or more parties for the purchase and/or sale of Capacity or Energy other than those in the ISO Administered Markets. A request to schedule

a Bilateral Transaction in the Energy Market shall be considered a request to schedule Point-to-Point Transmission Service.

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

2.3 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 Limited Resource: A Resource that is constrained in its ability to supply Energy above its Normal Upper Operating Limit by operational or plant configuration characteristics. Capacity Limited Resources must register their Capacity limiting characteristics with, and justify them to, the ISO consistent with ISO Procedures. 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.

Capacity Reservation Cap: The maximum percentage of transmission Capacity from a Transmission Owner’s sets of ETCNL that may be converted into ETCNL TCCs or the maximum percentage of a Transmission Owner’s RCRRs that may be converted into RCRR

TCCs, as the case may be, as established by the ISO pursuant to Section 19.4.3 of Attachment M of the 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”): The process by which TCCs are released for sale for the Centralized TCC Auction period, through a bidding process administered by the ISO or an auctioneer.

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.

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

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

For Suppliers not covered by other provisions of this Section and Intermittent Power Resources depending on wind as their fuel for which the ISO has imposed a Wind 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 which is operating in Start-Up or Shutdown Periods, or Testing Periods, or which is an Intermittent Power Resource that depends on solar energy or landfill gas for its fuel and which has offered its Energy to the ISO in a given interval not using the ISO-committed Flexible or Self-Committed Flexible bid mode, Compensable Overgeneration shall mean all Energy actually injected by the Generator that exceeds the Real-Time Scheduled Energy Injection established by the ISO for that Generator. For a Generator 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 injected by the Generator that exceeds the Real-Time Scheduled Energy Injection up to the Energy level directed by the Transmission Owner or the ISO.

For Intermittent Power Resources that depend on wind as their fuel and Limited Control Run of River Hydro Resources not using the ISO-Committed Flexible or Self-Committed Flexible bid mode, that were in operation on or before November 18, 1999 within the NYCA, plus an additional 3,300 MW of such Resources, Compensable Overgeneration shall mean that quantity of Energy injected by a Generator, over a given RTD interval that exceeds the Real-Time Scheduled Energy Injection established by the ISO for that Generator and for which the Generator may be paid pursuant to ISO Procedures; provided however, this definition of Compensable Overgeneration shall not apply to an Intermittent Power Resource depending on wind as its fuel for any interval for which the ISO has imposed a Wind Output Limit.

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 Injection 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: The opportunity costs of transmission Constraints on the NYS Transmission System. Congestion Rents are collected by the ISO from Loads through its facilitation of LBMP Market Transactions and the collection of Transmission Usage Charges from Bilateral Transactions.

Congestion Rent Shortfall: A condition in which the Congestion Rent revenue collected by the ISO in the Day-Ahead Market for Energy is less than the amount of Congestion Rent revenue in the Day-Ahead Market for Energy that the ISO is obligated under the ISO OATT to pay out to the Primary Holders of TCCs.

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 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.

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.

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.

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.

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.

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

Curtailement Customer Aggregator: A Curtailement 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 Curtailement Customer Aggregator is set forth in ISO procedures.

Curtailement 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.

Curtailement 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 Curtailement Services Provider is set forth in Section 3 below and in ISO Procedures.

Curtailement Services Provider Capacity: Capacity from a Demand Side Resource nominated by a Curtailement 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.

2.9 Definitions - I

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

ICAP Demand Curve Reset Filing Year: A calendar year in which the ISO files ICAP Demand Curves, in accordance with Section 5.14.1.2.11.

ICAP Ineligible Forced Outage: The outage state of a Market Participant's Generator after: i) the expiration or termination of its Forced Outage pursuant to the provisions in Section 5.18.1.6 of this Services Tariff, which Forced Outage started on or after the effective date of Section 5.18 of this Services Tariff; ii) the Market Participant voluntarily reclassified its Forced Outage pursuant to the provisions in Section 5.18.2.1 of this Services Tariff, which Forced Outage started on or after the effective date of Section 5.18 of this Services Tariff; or iii) substantial actions have been taken, such as dismantling or disabling essential equipment, which actions are inconsistent with an intention to return the Generator to operation and the Energy market. A Generator in an ICAP Ineligible Forced Outage is subject to the return-to-service provisions in Section 5.18.4 of this Services Tariff and is ineligible to participate in the Installed Capacity market.

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

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

Import Curtailment Guarantee Payment: A payment made in accordance with Section 4.5.3.2 and Attachment J of this ISO Services Tariff to compensate a Supplier whose Import is Curtailed by the ISO.

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

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

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

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

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

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

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

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

Incremental TCC: A set of point-to-point Transmission Congestion Contract(s) that is awarded pursuant to Section 19.2.2 of Attachment M to the ISO OATT.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Investor-Owned Transmission Owners: At the present time these include: Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State

Electric & Gas Corporation, Niagara Mohawk Power Corporation, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation.

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

ISO-Committed Fixed: In the Day-Ahead Market, a bidding mode in which a Generator requests that the ISO commit and schedule it. In the Real-Time Market, a bidding mode in which a Generator, with ISO approval, requests that the ISO schedule it no more frequently than every 15 minutes. A Generator scheduled in the Day-Ahead Market as ISO-Committed Fixed will participate as a Self-Committed Fixed Generator in the Real-Time Market unless it changes bidding mode, with ISO approval, to participate as an ISO-Committed Fixed Generator.

ISO-Committed Flexible: A bidding mode in which a Dispatchable Generator or Demand Side Resource follows Base Point Signals and is committed by the ISO.

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

ISO OATT: The ISO Open Access Transmission Tariff.

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

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

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

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

2.16 Definitions - P

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

Performance Tracking System: A system designed to report metrics for Generators 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 ("POP" 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: A Primary Holder of each TCC is the Primary Owner of that TCC or the party that purchased that TCC at the close of the Centralized TCC Auction. With respect to each TCC, a Primary Holder must be: (1) a Transmission Customer that has purchased the TCC in the Centralized TCC Auction, and that has not resold it in that same Auction; (2) a Transmission Customer that has purchased the TCC in a Direct Sale with another Transmission Customer; (3) the Primary Owner who has retained the TCC; or (4) Primary Owners of the TCC that allocated the TCC to certain customers or sold it in the Secondary Market or sold through a Direct Sale to an entity other than a Transmission Customer. The ISO settles Day-Ahead Congestion Rents pursuant to Attachments M and N to the ISO OATT with the Primary Holder of each TCC.

Primary Owner: The Primary Owner of each TCC is the Transmission Owner or other Transmission Customer that has acquired the TCC through conversion of rights under an Existing Transmission Agreement to Grandfathered TCCs (in accordance with Attachment K of the ISO OATT), or through the conversion of Existing Transmission Agreements upon their expiration (in accordance with Attachment B), or the Transmission Owner that acquired the TCC through the ISO's allocation of Original Residual TCCs or through the conversion of ETCNL or an RCRR.

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.

4.4 Real-Time Markets and Schedules

4.4.1 Real-Time Commitment (“RTC”)

4.4.1.1 Overview

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

4.4.1.2 Bids and Other Requests

After the Day-Ahead schedule is published and before the close of the Real-Time Scheduling Window for each hour, Customers may submit Real-Time Bids into the Real-Time Market for real-time evaluation by providing all information required to permit real-time evaluation pursuant to ISO Procedures.

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

Intermittent Power Resources that depend on wind as their fuel submitting new or revised offers to supply Energy shall bid as ISO-Committed Flexible and shall submit a Minimum

Generation Bid of zero MW and zero cost and a Start-Up Bid at zero cost. Eligible Customers may submit new or revised Bids to supply Energy, Operating Reserves and/or Regulation Service. Customers that submit such Bids may specify different Bid parameters in real-time than they did Day-Ahead. Incremental Energy Bids may be submitted by Suppliers bidding Resources using ISO-Committed Fixed, ISO-Committed Flexible, and Self-Committed Flexible bid modes that exceed the Incremental Energy Bids submitted in the Day-Ahead Market or the mitigated Day-Ahead Incremental Energy Bids where appropriate, for portions of the Capacity of such Resources that were scheduled in the Day-Ahead Market, if not otherwise prohibited pursuant to other provisions of the tariff. Minimum Generation Bids, Start-Up Bids, Regulation Service Bids for any hour in which such Resources received a Day-Ahead Energy schedule or a Regulation Service schedule, as appropriate, may not exceed the Minimum Generation Bids, Start-up Bids, or Regulation Service Bids, as appropriate, submitted for those Resources in the Day-Ahead Market. Additionally, Real-Time Minimum Run Qualified Gas Turbine Customers shall not increase their previously submitted Real-Time Incremental Energy Bids, Minimum Generation Bids, or Start-Up Bids within 135 minutes of the dispatch hour. Bids to supply Energy or Ancillary Services shall be subject to the rules set forth in Section 4.2.1 of this ISO Services Tariff.

Suppliers bidding on behalf of Generators that did not receive a Day-Ahead schedule for a given hour may offer their Generators, for those hours, using the ISO-Committed Flexible, Self-Committed Flexible, Self-Committed Fixed bid mode or, with ISO approval, the ISO-Committed Fixed bid modes in real-time. Suppliers bidding on behalf of Demand Side Resources that did not receive a Day-Ahead schedule to provide Operating Reserves or Regulation Service for a given hour may offer to provide Operating Reserves or Regulation

Service using the ISO-Committed Flexible bid mode for that hour in the Real-Time Market provided, however, that the Demand Side Resource shall have an Energy price Bid no lower than the Monthly Net Benefit Offer Floor. A Supplier bidding on behalf of a Generator that received a Day-Ahead schedule for a given hour may not change the bidding mode for that Generator for the Real-Time Market for that hour provided, however, that Generators that were scheduled Day-Ahead in Self-Committed Fixed mode may switch, with ISO approval, to ISO-Committed Fixed bidding mode in real-time. Generators that were scheduled Day-Ahead in ISO-Committed Fixed mode will be scheduled as Self-Committed Fixed in the Real-Time Market unless, with ISO approval, they change their bidding mode to ISO-Committed Fixed.

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

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

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

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

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

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

4.4.1.2.3 Self-Commitment Requests

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

4.4.1.2.4 ISO-Committed Fixed

The ability to use the ISO-Committed Fixed bidding mode in the Real-Time Market shall be subject to ISO approval pursuant to procedures, which shall be published by the ISO.

Generators that have exclusively used the Self-Committed Fixed or ISO-Committed Fixed bid

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

RTC shall schedule ISO-Committed Fixed Generators.

4.4.1.3 External Transaction Scheduling

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

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

Except as specifically noted in Section 4.4.2, 4.4.3 and 4.4.4 of this ISO Services Tariff, RTC will make all Resource commitment and de-commitment decisions. RTC will make all economic commitment/de-commitment decisions based upon available offers assuming Suppliers internal to the NYCA have a one-hour minimum run time; provided however, Real-Time Minimum Run Qualified Gas Turbines shall be assumed to have a two-hour minimum run time.

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

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

- (i) Commit Resources with 10-minute start-up times that should be synchronized by the time that the results of the next RTC run are posted so that they will be synchronized and running at their scheduled generation levels by that time;
- (ii) Commit Resources with 30-minute start-up times that should be synchronized by the time that the results of the RTC run following the next RTC run are posted so that they will be synchronized and running at their scheduled generation levels by that time;
- (iii) De-commit Resources that should be disconnected from the network by the time that the results of the next RTC run are posted so that they will be disconnected by that time;

- (iv) Issue advisory commitment and de-commitment guidance for periods more than thirty minutes in the future and advisory dispatch information;
- (v) Schedule economic hourly External Transactions for the next hour;
- (vi) Schedule economic 15 minute External Transactions, for the quarter hour for which the results of the next RTC run are posted, at Variably Scheduled Proxy Generator Buses other than a CTS Enabled Proxy Generator Bus;
- (vii) Schedule economic 15 minute External Transactions, for the quarter hour for which the results of the next RTC run are posted, at a CTS Enabled Proxy Generator Bus; and
- (viii) Schedule ISO-Committed Fixed Resources.

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

- (i) Commit Resources with 10-minute start-up times that should be synchronized by the time that the results of the next RTC run are posted so that they will be synchronized and running at that time;
- (ii) Commit Resources with 30-minute start-up times that should be synchronized by the time that the results of the RTC run following the next RTC run are posted so that they will be synchronized and running at that time;
- (iii) De-commit Resources that should be disconnected from the network by the time that the results of the next RTC run are posted so that they will be disconnected at that time;

- (iv) Issue advisory commitment, de-commitment, and dispatching guidance for the period from thirty minutes in the future until the end of the RTC co-optimization period;
- (v) Either reaffirm that the External Transactions scheduled by previous RTC runs should continue to flow in the next hour, or inform the ISO that External Transactions may need to be reduced;
- (vi) Schedule economic 15 minute External Transactions, for the quarter hour for which the results of the next RTC run are posted, at Variably Scheduled Proxy Generator Buses other than a CTS Enabled Proxy Generator Bus;
- (vii) Schedule economic 15 minute External Transactions, for the quarter hour for which the results of the next RTC run are posted, at a CTS Enabled Proxy Generator Bus; and
- (viii) Schedule ISO-Committed Fixed Resources.

4.4.1.5 External Transaction Settlements

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

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

4.4.2 Real-Time Dispatch

4.4.2.1 Overview

The Real-Time Dispatch will make dispatching decisions, send Base Point Signals to Internal Generators and Demand Side Resources, produce schedules for intra-hour External

Transactions at Dynamically Scheduled Proxy Generator Buses, calculate Real-Time Market clearing prices for Energy, Operating Reserves, and Real-Time Market Prices for Regulation Service, and establish real-time schedules for those products on a five-minute basis, starting at the beginning of each hour. The Real-Time Dispatch will not make commitment decisions and will not consider start-up costs in any of its dispatching or pricing decisions, except as specifically provided in Section 4.4.2.3 below. Each Real-Time Dispatch run will co-optimize to solve simultaneously for Load, Operating Reserves, and Regulation Service and to minimize the total cost of production over its bid optimization horizon (which may be fifty, fifty-five, or sixty minutes long depending on where the run falls in the hour.) In addition to producing a binding schedule for the next five minutes, each Real-Time Dispatch run will produce advisory schedules for the remaining four time steps of its bid-optimization horizon (which may be five, ten, or fifteen minutes long depending on where the run falls in the hour). An advisory schedule may become binding in the absence of a subsequent Real-Time Dispatch run. RTD will use the most recent system information and the same set of Bids and constraints that are considered by RTC.

4.4.2.2 External Transaction Scheduling

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

4.4.2.3 Calculating Real-Time Market LBMPs and Advisory Prices

RTD shall calculate *ex ante* Real-Time LBMPs at each Generator bus, and for each Load Zone in each RTD cycle, in accordance with the procedures set forth in Attachment B to this ISO

Services Tariff. RTD will also calculate and post advisory Real-Time LBMPs for the next four quarter hours in accordance with the procedures set forth in Attachment B.

4.4.2.4 Real-Time Pricing Rules for Scheduling Ten Minute Resources

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

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

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

being provided by a Special Case Resource, provided such Demand Reduction is otherwise payable as a reduction by a Special Case Resource.

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

Special Case Resource Capacity that has been scheduled in the Day-Ahead Market to provide Operating Reserves, Regulation Service or Energy and that has been instructed as a Special Case Resource to reduce demand shall be considered, for the purpose of applying Real-Time special scarcity pricing rules described in Attachment B of this Services Tariff, to be a Special Case Resource.

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

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

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

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

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

Curtailment Services Provider Capacity that has been scheduled in the Day-Ahead Market as Operating Reserves, Regulation Service or Energy and that has been instructed to reduce demand shall be considered, for the purpose of applying Real-Time special scarcity pricing rules described in Attachment B of this Services Tariff, to be a Emergency Demand Response Program Resource.

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

4.4.2.7 Real-Time Scarcity Pricing Rules Applicable to Regulation Service and Operating Reserves During EDRP and/or SCR Activations

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

4.4.2.8 Post the Real-Time Schedule

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

4.4.3 Real-Time Dispatch - Corrective Action Mode

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

The ISO shall have discretion to determine which specific RTD-CAM mode should be activated in particular situations. In addition, RTD-CAM may require Resources to run above their UOL_{NS} , up to the level of their UOL_{ES} as is described in the ISO Procedures. Self-

Committed Fixed Resources will not be expected to move in response to RTD-CAM Base Point Signals except when a maximum generation pickup is activated.

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

4.4.3.1 RTD-CAM Modes

4.4.3.1.1 Reserve Pickup

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

The ISO will have discretion to classify a reserve pickup as a “large event” or a “small event.” In a small event the ISO will have discretion to reduce Base Point Signals in order to reduce transmission line loadings. The ISO will not have this discretion in large events. The distinction also has significance with respect to a Supplier’s eligibility to receive Bid Production Cost guarantee payment in accordance with Section 4.6.6 and Attachment C of this ISO Services Tariff.

4.4.3.1.2 Maximum Generation Pickup

The ISO will enter this RTD-CAM mode when an Emergency makes it necessary to maximize Energy production in one or more location(s), i.e., Long Island, New York City, East

of Central East and/or NYCA-wide. RTD-CAM will produce schedules directing all Generators located in a targeted location to increase production at their emergency response rate up to their UOL_E level and to stay at that level until instructed otherwise. Security constraints will be obeyed to the extent possible. The ISO will continue to optimize for Energy and Operating Reserves, will recognize locational Operating Reserve requirements, but will set all Regulation Service schedules to zero.

4.4.3.1.3 Base Points ASAP -- No Commitments

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

4.4.3.1.4 Base Points ASAP -- Commit As Needed

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

4.4.3.1.5 Re-Sequencing Mode

When the ISO is ready to de-activate RTD-CAM, it will often need to transition back to normal Real-Time Dispatch operation. In this mode, RTD-CAM will calculate normal five-minute Base Point Signals and establish five minute schedules. Unlike the normal RTD-

Dispatch, however, RTD-CAM will only look ahead 10-minutes. RTD-CAM re-sequencing will terminate as soon as the normal Real-Time Dispatch software is reactivated and is ready to produce Base Point signals for its entire optimization period.

4.4.3.2 Calculating Real-Time LBMPs

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

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

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

Proxy Generator Bus	PTID	Scheduled Line	Designated Scheduled Line	Non-Competitive	CTS Enabled Proxy Generator Bus		Scheduling Frequencies		
					Requires CTS Bids	Permits CTS Bids	Hourly Scheduled	Variably Scheduled	Dynamically Scheduled (Not Presently Available)
Hydro Quebec									
HQ_GEN_IMPORT	323601			✓			✓	✓	
HQ_LOAD_EXPORT	355639			✓			✓	✓	
HQ_GEN_CEDARS_PROXY	323590	Dennison Scheduled Line		✓			✓		
HQ_LOAD_CEDARS_PROXY	355586	Dennison Scheduled Line		✓			✓		
HQ_GEN_WHEEL	23651			✓			✓		
HQ_LOAD_WHEEL	55856			✓			✓		
PJM									
PJM_GEN_KEYSTONE	24065						✓	✓	
PJM_LOAD_KEYSTONE	55857						✓	✓	
PJM_GEN_NEPTUNE_PROXY	323594	Neptune Scheduled Line	✓				✓	✓	
PJM_LOAD_NEPTUNE_PROXY	355615	Neptune Scheduled Line	✓				✓	✓	
PJM_GEN_VFT_PROXY	323633	Linden VFT Scheduled Line	✓				✓	✓	
PJM_LOAD_VFT_PROXY	355723	Linden VFT Scheduled Line	✓				✓	✓	
PJM_HTP_GEN	323702	HTP Scheduled Line	✓				✓	✓	
HUDSONTP_345KV_HTP_LOAD	355839	HTP Scheduled	✓				✓	✓	

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)
		Line							
ISO New England									
N.E._GEN_SANDY_POND	24062						✓		
NE_LOAD_SANDY_PD	55858						✓		
NPX_GEN_CSC	323557	Cross Sound Scheduled Line	✓				✓		
NPX_LOAD_CSC	355535	Cross Sound Scheduled Line	✓				✓		
NPX_GEN_1385_PROXY	323591	Northport Norwalk Scheduled Line					✓		
NPX_LOAD_1385_PROXY	355589	Northport Norwalk Scheduled Line					✓		
Ontario									
O.H._GEN_BRUCE	24063						✓		
OH_LOAD_BRUCE	55859						✓		

Notes:

* At specifically identified Proxy Generator Buses (“* See Notes”), only Wheels Through 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.

26.4 Operating Requirement and Bidding Requirement

26.4.1 Purpose and Function

The Operating Requirement is a measure of a Customer's expected financial obligations to the ISO based on the nature and extent of that Customer's participation in ISO-Administered Markets. A Customer shall be required to allocate Unsecured Credit, where allowed, and/or provide collateral in an amount equal to or greater than its Operating Requirement. Upon a Customer's written request, the ISO will provide a written explanation for any changes in the Customer's Operating Requirement.

The Bidding Requirement is a measure of a Customer's potential financial obligation to the ISO based upon the bids that Customer seeks to submit in an ISO-administered TCC or ICAP auction. A Customer shall be required to allocate Unsecured Credit, where allowed, and/or provide collateral in an amount equal to or greater than its Bidding Requirement prior to submitting bids in an ISO-administered TCC or ICAP auction.

26.4.2 Calculation of Operating Requirement

The Operating Requirement shall be equal to the sum of (i) the Energy and Ancillary Services Component; (ii) the External Transaction Component; (iii) the UCAP Component; (iv) the TCC Component; (v) the WTSC Component; (vi) the Virtual Transaction Component; (vii) the DADRP Component; and (viii) the DSASP Component where:

26.4.2.1 Energy and Ancillary Services Component

The Energy and Ancillary Services Component shall be equal to:

- (a) For Customers without a prepayment agreement, the greater of either:

$$\frac{\text{Basis Amount for Energy and Ancillary Services}}{\text{Days in Basis Month}} \times 16$$

- or -

$$\frac{\text{Total Charges Incurred for Energy and Ancillary Services for Previous Ten (10) Days}}{10} \times 16$$

- (b) For Customers that qualify for a prepayment agreement, subject to the ISO's credit analysis and approval, and execute a prepayment agreement in the form provided in Appendix K-1, the greater of either:

$$\frac{\text{Basis Amount for Energy and Ancillary Services}}{\text{Days in Basis Month}} \times 3$$

or-

$$\frac{\text{Total Charges Incurred for Energy and Ancillary Services for Previous Ten (10) Days}}{10} \times 3$$

- (c) For new Customers, the ISO shall determine a substitute for the Basis Amount for Energy and Ancillary Services for use in the appropriate formula above equal to:

$$\text{EPL} \times 720 \times \text{AEP}$$

where:

EPL = estimated peak Load for the Capability Period; and

AEP = average Energy and Ancillary Services price during the Prior Equivalent Capability Period after applying the Price Adjustment.

26.4.2.2 External Transaction Component

The External Transaction Component shall equal the sum of the Customer's (i) Import Credit Requirement, (ii) Export Credit Requirement, (iii) Wheels Through Credit Requirement, and (iv) the net amount owed to the ISO for the settled External Transaction Component Transactions.

26.4.2.2.1 Import Credit Requirement

For a given month, the Import Credit Requirement shall apply to any Customer that Bids to Import in the Day-Ahead Market (“DAM”) unless (i) the Customer has at least 50 scheduled Day-Ahead Import Bids in the three-month period ending on the 15th day of the preceding month (or the six-month period ending on the 15th day of the preceding month if the Customer has fewer than 50 scheduled Day-Ahead Import Bids in the immediately preceding three-month period), and (ii) fewer than 25% of the MWhs of such scheduled Day-Ahead Import Bids were settled at a loss to the Customer.

The Import Credit Requirement shall equal the sum of the amounts calculated for each Bid in accordance with the appropriate formulas below:

(1) Upon submission of a DAM Import Bid until posting of the applicable DAM schedule/price.

The ISO will categorize each Import Bid into one of the 18 Import Price Differential (IPD) groups set forth in the IPD chart in Section 26.4.2.2.5 below, as appropriate, based upon the season and time-of-day of the Import Bid. The amount of credit support required in \$/MWh that applies to an Import Bid shall equal the 97th percentile level of the following: the hourly average Energy price calculated in the Real-Time Market at the location associated with the Import Bid, minus the Energy price calculated in the DAM at the same location and time, with the dataset used to perform this calculation consisting of all hours that are in the same IPD group as the hour to which the Import Bid applies, and that occurred no earlier than April 1, 2005 nor later than the end of the calendar month preceding the month to which the Import Bid applies. The amount of credit support required in \$/MWh shall not be less than \$0/MWh.

The credit requirement for each Import Bid shall be calculated as follows:

$$\text{Bid}_{\text{MWhB}} * \text{Max} (\text{IPD}_{\text{CS}}, 0)$$

Where:

Bid_{MWhB} = the total quantity of MWhs that a Customer Bids to Import in a particular hour and at a particular location.

IPD_{CS} = the amount of credit support required, in \$/MWh, for an Import Bid as described above, for the location associated with the Import Bid and for the IPD group that contains the hour to which the Import Bid applies.

(2) Upon posting of the applicable DAM schedule/price until completion of the hour Bid in real-time for a DAM Import Bid.

The credit requirement for each Import Bid shall be calculated as follows:

$$\text{SchBid}_{\text{MWhI}} * \text{Max} (\text{IPD}_{\text{CS}}, 0)$$

Where:

$\text{SchBid}_{\text{MWhI}}$ = the total quantity of MWhs that is scheduled in the DAM in a particular hour and at a particular location as a result of the Customer's Import Bid.

IPD_{CS} = the amount of credit support required, in \$/MWh, for an Import Bid as described above, for the location associated with the Import Bid and for the IPD group that contains the hour to which the Import Bid applies.

(3) Upon completion of the hour Bid in real-time for a DAM Import Bid until the net amount owed to the ISO is determined for settled External Transactions.

The credit requirement for each Import Bid shall be calculated as follows:

$$\text{Max} ((\text{BalPay}_{\$} - \text{DAMPay}_{\$}), 0)$$

Where:

$\text{BalPay}_{\$}$ = $(\text{SchBid}_{\text{MWhI}} - \text{Actual}_{\text{MWhI}}) * \text{RT LBMP}_{\text{I}}$

$\text{DAMPay}_{\$}$ = $\text{SchBid}_{\text{MWhI}} * \text{DAM LBMP}_{\text{I}}$

$\text{SchBid}_{\text{MWhI}}$ = the total quantity of MWhs that is scheduled in the DAM in a particular hour at a particular location as a result of the Customer's Import Bid.

$Actual_{MWhI}$ = the total quantity of MWhs that is scheduled in real-time associated with the Customer's Import Bid in a particular hour and at a particular location for the hour completed.

$DAM\ LBMP_I$ = the Day-Ahead LBMP in a particular hour and at a particular location associated with the Customer's Import Bid.

$RT\ LBMP_I$ = the Real-Time LBMP in a particular hour and at a particular location associated with the Customer's Import Bid.

26.4.2.2.2 Export Credit Requirement

The Export Credit Requirement shall apply to any Customer that Bids to Export from the DAM or Hour-Ahead Market ("HAM").

The Export Credit Requirement shall equal the sum of the amounts calculated for each Bid in accordance with the appropriate formulas below:

(1) Upon submission of a DAM Export Bid until posting of the applicable DAM schedule/price.

The ISO will categorize each Export Bid into one of the 18 Export Price Differential (EPD) groups set forth in the EPD chart in Section 26.4.2.2.5 below, as appropriate, based upon the season and time-of-day of the Export Bid. The amount of credit support required in \$/MWh that applies to an Export Bid shall equal the 97th percentile level of the following: the Energy price calculated in the DAM at the location associated with the Export Bid, minus the hourly average Energy price calculated in the Real-Time Market at the same location and time, with the dataset used to perform this calculation consisting of all hours that are in the same EPD group as the hour to which the Export Bid applies, and that occurred no earlier than April 1, 2005 nor later than the end of the calendar month preceding the month to which the Export Bid applies. The amount of credit support required in \$/MWh shall not be less than \$0/MWh.

The credit requirement for all DAM Export Bids with the same hour/date and location shall be calculated as follows:

$$(\text{Max} ((\text{Max}_N(\text{Bid}_{\text{MWh}} * \text{Bid}_{\text{\$E}})), (\text{BidMax}_{\text{MWhB}} * \text{EPD}_{\text{CS}})))$$

Where:

- Bid_{MWh} = the total quantity of MWhs that a Customer Bids to Export in the DAM in a particular hour and at a particular location at or below each Bid Price.
- $\text{Bid}_{\text{\$E}}$ = the Bid Price in \\$/MWh at which the Customer Bids to purchase the Bid_{MWh} of Exports in a particular hour and at a particular location.
- N = the set of hourly Export Bid Prices in a particular hour and at a particular location.
- $\text{BidMax}_{\text{MWhB}}$ = the total quantity of MWhs that a Customer Bids to Export in the DAM in a particular hour and at a particular location.
- EPD_{CS} = the amount of credit support required, in \\$/MWh, for an Export Bid as described above, for the location associated with the Export Bid and for the EPD group that contains the hour to which the Export Bid applies.

(2) Upon posting of the applicable DAM schedule/price until completion of hour Bid in real-time for a DAM Export Bid.

The credit requirement for each Export Bid shall be calculated as follows:

$$(\text{SchBid}_{\text{MWhE}} * (\text{Max} (\text{EPD}_{\text{CS}}, \text{DAM LBMP}_{\text{E}})))$$

Where:

- $\text{SchBid}_{\text{MWhE}}$ = the total quantity of MWhs that is scheduled in the DAM in a particular hour at a particular location as a result of the Customer's Export Bid.
- EPD_{CS} = the amount of credit support required, in \\$/MWh, for an Export Bid as described above, for the location associated with the Export Bid and for the EPD group that contains the hour to which the Export Bid applies.
- $\text{DAM LBMP}_{\text{E}}$ = the Day-Ahead LBMP in a particular hour and at a particular location associated with the Customer's Export Bid.

(3) From submission of a HAM Export Bid until completion of the hour Bid in real-time.

i. For non-CTS Interface Bid HAM Bids to Export credit support will be calculated upon submission.

The amount of credit support required in \$/MWh that applies to HAM Export Bids in the same hour/date and at the same location shall equal the maximum amount of the payment potentially due to the ISO based on the MWhs of Exports Bid for purchase at each bid price in a particular hour and at a particular location.

The credit requirement for all HAM Export Bids with the same hour/date and location shall be calculated as follows:

$$(\text{Max}_N ((\text{Max} (\text{Bid}_{\text{MWhE}}, 0)) * \text{Bid}_{\$E}))$$

Where:

- Bid_{MWhE} = the total quantity of MWhs that a Customer Bids to Export in the HAM in a particular hour and at a particular location at or below each bid price minus the MWhs of Exports scheduled in the DAM in the same hour at the same location.
- $\text{Bid}_{\$E}$ = the bid price in \$/MWh at which the Customer Bids to purchase the Bid_{MWhE} of Exports in a particular hour and at a particular location.
- N = the set of hourly Export bid prices in a particular hour and at a particular location.

ii. For CTS Interface Bids to Export credit support will be calculated at HAM market close.

The amount of credit support required in \$/MWh that applies to such bid shall equal the sum of the time-weighted hourly RTC price for each of the 15-minute intervals within the bid hour, not to be less than zero.

The credit requirement for each CTS Interface Bid to Export shall be calculated as follows:

$$\text{Max} (\sum_N (\text{RTC}_{\$/\text{MWhcts}} * \text{Bid}_{\text{MWhcts}} * \text{Hourly Weight}), 0)$$

Where:

N = each 15-minute interval within the bid hour.

$\text{RTC}_{\$/\text{MWhcts}}$ = most recently available RTC price for N in $\$/\text{MWh}$ at the location associated with the CTS Interface Bid to Export

$\text{Bid}_{\text{MWhcts}}$ = the total quantity of MWhs in a Customer's CTS Interface Bid to Export for N in a particular hour and at a particular location minus the MWhs of Exports scheduled in the DAM in same hour at the same location.

Hourly Weight = 0.25

(4) Upon completion of the hour Bid in real-time for an Export Bid until the net amount owed to the ISO is determined for settled External Transactions.

The amount of credit support required will equal the sum of the Day-Ahead Credit Calculation and Real-Time Credit Calculation for each completed hour.

The credit requirement for each Export Bid shall be calculated as follows:

Day-Ahead Credit Calculation + Real-Time Credit Calculation

The Day-Ahead Credit Calculation only applies to DAM Export Bids and the Real-Time Credit Calculation applies to all HAM Export Bids including HAM Bids associated with a DAM Bid.

Where:

Day-Ahead Credit Calculation = Max (Adjusted Export Day-Ahead Credit Calculation, 0)

Adjusted Export Day-Ahead Credit Calculation = the credit requirement calculated in accordance with section 26.4.2.2.2(2) minus the Balancing Payment.

Balancing Payment = Max ((SchBid_{MWhE} – Actual_{MWhE}), 0) * RT LBMP_E

SchBid_{MWhE} = the total quantity of MWhs that is scheduled in the DAM in a particular hour and at a particular location as a result of the Customer's Export Bid.

$Actual_{MWhE}$ = the total quantity of MWhs that is scheduled in real-time associated with the Customer's Export Bid in a particular hour and at a particular location for the hour completed.

$RT\ LBMP_E$ = the Real-Time LBMP in a particular hour and at a particular location associated with the Customer's Export Bid.

Real-Time Credit Calculation = $\text{Max} ((\text{Max} ((Actual_{MWhE} - SchBid_{MWhE}), 0) * RT\ LBMP_E), 0)$

$Actual_{MWhE}$ = the total quantity of MWhs that is scheduled in real-time associated with the Customer's Export Bid in a particular hour and at a particular location for the hour completed.

$SchBid_{MWhE}$ = the total quantity of MWhs that is scheduled in the DAM in a particular hour and at a particular location as a result of the Customer's Export Bid.

$RT\ LBMP_E$ = the Real-Time LBMP in a particular hour and at a particular location associated with the Customer's Export Bid.

26.4.2.2.3 Wheels Through Credit Requirement

The Wheels Through Credit Requirement shall apply to any Customer that Bids to Wheel Through in the DAM or HAM.

The Wheels Through Credit Requirement shall equal the sum of the amounts calculated for each Bid in accordance with the appropriate formulas below:

(1) Upon submission of a DAM Wheels Through Bid until posting of the applicable DAM schedule/price.

The amount of credit support required in \$/MWh that applies to the DAM Wheels Through Bid shall equal the maximum payment potentially due to the ISO based on the Customer's Bid Prices on the Bid curve.

The credit requirement for each Wheels Through Bid shall be calculated as follows:

$$\text{Max} (\text{Max}_N (BidPt_{MWhN} * Bid\$/_{MWhN}), 0)$$

Where:

N = each Bid Price on the Bid curve.

$BidPt_{MWhN}$ = the MWhs associated with the Bid Price on the Bid curve.

$Bid\$/MWhN$ = the amount that the customer is willing to pay for congestion in \$/MWh on the Bid curve associated with the Customer's Wheels Through Bid.

(2) Upon posting of the applicable Wheels Through DAM schedule/price until completion of the hour Bid in real-time.

The credit requirement for each DAM Wheels Through Bid shall be calculated as follows:

$$\text{Max} (\text{SchBid}_{MWhW} * (\text{DAM LBMP}_{POW} - \text{DAM LBMP}_{POI}), 0))$$

Where:

SchBid_{MWhW} = the total quantity of MWhs scheduled in the DAM as a result of the Customer's Bid to schedule Wheels Through.

DAM LBMP_{POI} = the Day-Ahead LBMP in the hour and at the Point of Injection associated with the Wheels Through Bid.

DAM LBMP_{POW} = the Day-Ahead LBMP in the hour and at the Point of Withdrawal associated with the Wheels Through Bid.

(3) Upon creation of a HAM Wheels Through Bid until the completion of the hour Bid in real-time.

The amount of credit support required in \$/MWh that applies to HAM Wheels Through Bid shall equal the price of the maximum value of exposure based on bid prices on the Bid curve.

The credit requirement for each Wheels Through Bid shall be calculated as follows:

$$\text{Max}(\text{Max}_N (\text{Max} (\text{BidPt}_{MWhW}, 0) * \text{Bid}\$/MWhN), 0)$$

Where:

N = each bid price on the Bid curve.

$BidPt_{MWhW}$ = the MWhs associated with the bid price on the Bid curve minus the MWhs of the DAM Bid with same hour/date, location and Bid transaction ID.

$Bid\$/MWhN$ = the amount that the customer is willing to pay for congestion in \$/MWh on the Bid curve associated with the Customer's Wheels Through Bid.

(4) Upon completion of the hour Bid in real-time for a Wheels Through Bid until the net amount owed to the ISO is determined for settled External Transactions.

The amount of credit support required will equal the sum of the Day-Ahead Credit Calculation and Real-Time Credit Calculation for each completed hour.

The credit requirement for each Wheels Through Bid shall be calculated as follows:

Day-Ahead Credit Calculation + Real-Time Credit Calculation

The Day-Ahead Credit Calculation only applies to DAM Wheels Through Bids and the Real-Time Credit Calculation applies to all HAM Wheels Through Bids including HAM Bids associated with a DAM Bid.

Where:

Day-Ahead Credit Calculation = Max (Adjusted Wheels Through Day-Ahead Credit Calculation, 0)

Adjusted Wheels Through Day-Ahead Credit Calculation = the credit requirement calculated in section 26.4.2.2.3(2) minus the Balancing Payment.

Balancing Payment = $\text{Max} ((\text{SchBid}_{MWhW} - \text{Actual}_{MWhW}), 0) * (\text{RT LBMP}_{POW} - \text{RT LBMP}_{POI})$

SchBid_{MWhW} = the total quantity of MWhs that is scheduled in the DAM as a result of the Customer's Wheels Through Bid.

Actual_{MWhW} = the total quantity of MWhs that is scheduled in real-time associated with the Customer's Wheels Through Bid for the hour completed.

RT LBMP_{POI} = the Real-Time LBMP in the hour and at the Point of Injection associated with the Wheels Through Bid.

RT LBMP_{POW} = the Real-Time LBMP in the hour and at the Point of Withdrawal associated with the Wheels Through Bid.

$$\text{Real-Time Credit Calculation} = \text{Max} (\text{Max} ((\text{Actual}_{\text{MWhW}} - \text{SchBid}_{\text{MWhW}}), 0) * (\text{RT LBMP}_{\text{POW}} - \text{RT LBMP}_{\text{POI}}), 0)$$

$\text{SchBid}_{\text{MWhW}}$ = the total quantity of MWhs that is scheduled in the DAM as a result of the Customer's Bid to Wheel Through Energy.

$\text{Actual}_{\text{MWhW}}$ = the total quantity of MWhs that is scheduled in real-time associated with the Customer's Wheels Through Bid for the hour completed.

$\text{RT LBMP}_{\text{POI}}$ = the Real-Time LBMP in the hour and at the Point of Injection associated with the Wheels Through Bid.

$\text{RT LBMP}_{\text{POW}}$ = the Real-Time LBMP in the hour and at the Point of Withdrawal associated with the Wheels Through Bid.

26.4.2.2. 4 Calculation of Price Differentials

Import Price Differential (IPD) Groups

	For each Proxy Generator Bus
Summer	
HB07–10	IPD-1
HB11–14	IPD-2
HB15–18	IPD-3
HB19–22	IPD-4
Weekend/ Holiday (HB07–22)	IPD-5
Night (HB23–06)	IPD-6
Winter	
HB07–10	IPD-7
HB11–14	IPD-8
HB15–18	IPD-9
HB19–22	IPD-10
Weekend/ Holiday (HB07–22)	IPD-11
Night (HB23–06)	IPD-12
Rest-of-Year	
HB07–10	IPD-13
HB11–14	IPD-14
HB15–18	IPD-15
HB19–22	IPD-16
Weekend/ Holiday (HB07–22)	IPD-17
Night (HB23–06)	IPD-18

Where:

Summer = May, June, July, and August

Winter	=	December, January, and February
Rest-of-Year	=	March, April, September, October, and November
HB07–10	=	weekday hours beginning 07:00–10:00
HB11–14	=	weekday hours beginning 11:00–14:00
HB15–18	=	weekday hours beginning 15:00–18:00
HB19–22	=	weekday hours beginning 19:00– 22:00
Weekend/Holiday	=	weekend and holiday hours beginning 07:00–22:00
Night	=	all hours beginning 23:00– 06:00

Export Price Differential (EPD) Groups

	For each Proxy Generator Bus
Summer	
HB07–10	EPD-1
HB11–14	EPD-2
HB15–18	EPD-3
HB19–22	EPD-4
Weekend/ Holiday (HB07–22)	EPD-5
Night (HB23–06)	EPD-6
Winter	
HB07–10	EPD-7
HB11–14	EPD-8
HB15–18	EPD-9
HB19–22	EPD-10
Weekend/ Holiday (HB07–22)	EPD-11
Night (HB23–06)	EPD-12
Rest-of-Year	
HB07–10	EPD-13
HB11–14	EPD-14
HB15–18	EPD-15
HB19–22	EPD-16
Weekend/ Holiday (HB07–22)	EPD-17
Night (HB23–06)	EPD-18

Where:

Summer	=	May, June, July, and August
Winter	=	December, January, and February

Rest-of-Year	=	March, April, September, October, and November
HB07–10	=	weekday hours beginning 07:00–10:00
HB11–14	=	weekday hours beginning 11:00–14:00
HB15–18	=	weekday hours beginning 15:00–18:00
HB19–22	=	weekday hours beginning 19:00– 22:00
Weekend/Holiday	=	weekend and holiday hours beginning 07:00–22:00
Night	=	all hours beginning 23:00– 06:00

26.4.2.3 UCAP Component

The UCAP Component shall be equal to the total of all amounts then-owed (billed and unbilled) for UCAP purchased in the ISO-administered markets.

26.4.2.4 TCC Component

The TCC Component shall be equal to the greater of either the amount calculated in accordance with Section 26.4.2.4.1 or Section 26.4.2.4.2 below.

26.4.2.4.1 TCC Award Calculation

The sum of the amounts calculated in accordance with the appropriate per TCC term-based formula listed below for TCC purchases less the amounts calculated in accordance with the appropriate per TCC term-based formula listed below for TCC sales; *provided however*, that upon initial award of a TCC until the ISO receives payment for the TCC (or payment for the first year of a two-year TCC), the NYISO will hold the greater of the payment obligation for the TCC or the credit requirement for the TCC calculated in accordance with this Section 26.4.2.4.1.

26.4.2.4.1.1 Two-Year TCCs:

- (1) upon initial award of a two-year TCC until completion of the final round of the current two-year Sub-Auction, the sum of the first year and second year amounts, which will be calculated as follows:

First Year:

the amount calculated in accordance with the one-year TCC formula set forth in Section 26.4.2.4.1.5 below

where:

P_{ijt} = market clearing price of a one-year TCC in the final round of the one-year Sub-Auction in the prior Capability Period Centralized TCC Auction with the same POI and POW combination as the two-year TCC.

Second Year:

$$+1.909\sqrt{e^{10.9729 + .6514 \left(\ln \left(\frac{P_{ijt}}{P_{ijt}} \right) + e \right) + .6633 * Zone J + 1.1607 * Zone K}}$$

where:

P_{ijt} = market clearing price of that two-year TCC minus the market clearing price of a one-year TCC in the final round of the one-year Sub-Auction in the prior Capability Period Centralized TCC Auction with the same POI and POW combination as the two-year TCC

- (2) upon completion of the final round of the current two-year Sub-Auction until completion of the final round of the current one-year Sub-Auction, the sum of the first year and second year amounts, which will be calculated as follows:

First Year:

the amount calculated in accordance with the one-year TCC formula set forth in Section 26.4.2.4.1.5 below

where:

P_{ijt} = market clearing price of a one-year TCC in the final round of the one-year Sub-Auction in the prior Capability Period Centralized TCC Auction with the same POI and POW combination as the two-year TCC

Second Year:

$$+1.909 \sqrt{e^{10.9729 + .6514 (\ln(p_{ijt} + e)) + .6633 * Zone J + 1.1607 * Zone K}}$$

where:

Pijt = market clearing price of a two-year TCC in the final round of the current two-year Sub-Auction with the same POI and POW combination as the two-year TCC minus the market clearing price of a one-year TCC in the final round of the one-year Sub-Auction in the prior Capability Period Centralized TCC Auction with the same POI and POW combination as the two-year TCC

- (3) upon completion of the final round of the current one-year Sub-Auction until the ISO receives payment for the second year of the two-year TCC, the sum of the first year and second year amounts, which will be calculated as follows:

First Year:

the amount calculated in accordance with the one-year TCC formula set forth in Section 26.4.2.4.1.5 below

where:

Pijt = market clearing price of a one-year TCC in the final round of the current one-year Sub-Auction with the same POI and POW combination as the two-year TCC

Second Year:

$$+1.909 \sqrt{e^{10.9729 + .6514 (\ln(p_{ijt} + e)) + .6633 * Zone J + 1.1607 * Zone K}}$$

where:

Pijt = market clearing price of a two-year TCC in the final round of the current two-year Sub-Auction with the same POI and POW combination as the two-year TCC minus the market clearing price of a one-year TCC in the final round of the current one-year Sub-Auction with the same POI and POW combination as the two-year TCC

- (4) upon ISO receipt of payment for the second year of the two-year TCC until commencement of year two of the two-year TCC, the sum of the first year and second year amounts, which will be calculated as follows:

First Year:

the amount calculated in accordance with the one-year TCC formula set forth in Section 26.4.2.4.1.5 below

where:

Pijt = market clearing price of a one-year TCC in the final round of the one-year Sub-Auction in the prior equivalent Capability Period Centralized TCC Auction with the same POI and POW combination as the two-year TCC

Second Year:

the amount calculated in accordance with the one-year TCC formula set forth in Section 26.4.2.4.1.5 below

where:

Pijt = market clearing price of a one-year TCC in the final round of the one-year Sub-Auction in the prior equivalent Capability Period Centralized TCC Auction with the same POI and POW combination as the two-year TCC

- (5) upon commencement of year two of a two-year TCC until commencement of the final six months of the two-year TCC:

the amount calculated in accordance with the one-year TCC formula set forth in Section 26.4.2.4.1.5 below

where:

Pijt = market clearing price of a one-year TCC in the final round of the most recently completed one-year Sub-Auction with the same POI and POW combination as the two-year TCC

- (6) upon commencement of the final six months of a two-year TCC until commencement of the final month of the two-year TCC:

the amount calculated in accordance with the six-month TCC formula set forth in Section 26.4.2.4.1.5 below

where:

Pijt = market clearing price of a six-month TCC in the final round of the most recently completed six-month Sub-Auction with the same POI and POW combination as the two-year TCC

- (7) upon commencement of the final month of a two-year TCC:

the amount calculated in accordance with the one-month TCC formula set forth in Section 26.4.2.4.1.5 below

where:

P_{ijt} = market clearing price of a one-month TCC in the most recently completed monthly reconfiguration auction with the same POI and POW combination as the two-year TCC

26.4.2.4.1.2 One-Year TCCs:

- (1) upon initial award of a one-year TCC until completion of the final round of the current one-year Sub-Auction:

the amount calculated in accordance with the one-year TCC formula set forth in Section 26.4.2.4.1.5 below

- (2) upon completion of the final round of the current one-year Sub-Auction until commencement of the final six months of the one-year TCC:

the amount calculated in accordance with the one-year TCC formula set forth in Section 26.4.2.4.1.5 below

where:

P_{ijt} = market clearing price of a one-year TCC in the final round of the current one-year Sub-Auction with the same POI and POW combination as the one-year TCC

- (3) upon commencement of the final six months of a one-year TCC until commencement of the final month of the one-year TCC:

the amount calculated in accordance with the six-month TCC formula set forth in Section 26.4.2.4.1.5 below

where:

P_{ijt} = market clearing price of a six-month TCC in the final round of the most recently completed six-month Sub-Auction with the same POI and POW combination as the one-year TCC

- (4) upon commencement of the final month of a one-year TCC:

the amount calculated in accordance with the one-month TCC formula set forth in Section 26.4.2.4.1.5 below

where:

P_{ijt} = market clearing price of a one-month TCC in the most recently completed monthly reconfiguration auction with the same POI and POW combination as the one-year TCC

26.4.2.4.1.3 Six-Month TCCs:

- (1) upon initial award of a six-month TCC until completion of the final round of the current six-month Sub-Auction:

the amount calculated in accordance with the six-month TCC formula set forth in Section 26.4.2.4.1.5 below

- (2) upon completion of the final round of the current six-month Sub-Auction until commencement of the final month of a six-month TCC:

the amount calculated in accordance with the six-month TCC formula set forth in Section 26.4.2.4.1.5 below

where:

P_{ijt} = market clearing price of a six-month TCC in the final round of the current six-month Sub-Auction with the same POI and POW combination as the one-year TCC

- (3) upon commencement of the final month of a six-month TCC:

the amount calculated in accordance with the one-month TCC formula set forth in Section 26.4.2.4.1.5 below

where:

P_{ijt} = market clearing price of a one-month TCC in the most recently completed monthly reconfiguration auction with the same POI and POW combination as the six-month TCC

26.4.2.4.1.4 One-Month TCCs:

upon initial award of a one-month TCC:

the amount calculated in accordance with the one-month TCC formula set forth in Section 26.4.2.4.1.5 below

26.4.2.4.1.5 TCC formulas:

for one-year TCCs, representing a 5% probability curve:

$$+1.909 \sqrt{e^{10.9729 + .6514 (\ln(|p_{ijt}| + e)) + .6633 * Zone J + 1.1607 * Zone K}} - 1 P_{ijt}$$

for six-month TCCs, representing a 3% probability curve:

$$+2.565 - 1 P_{ijt}$$

for one-month TCCs, representing a 3% probability curve:

$$+2.221 \sqrt{e^{11.2682 + 0.3221 (\ln(|p_{ijt}| + e)) + 1.3734 * Zone J + 2.001 * Zone K + Month}} - 1 P_{ijt}$$

where:

P_{ijt} = market clearing price of i to j TCC in round t of the auction in which the TCC was purchased;

Zone J = 1 if TCC sources or sinks but not both in Zone J, zero otherwise;

Zone K = 1 if TCC sources or sinks but not both in Zone K and does not source or sink in Zone J, 0 otherwise;

Summer = 1 for six-month TCCs sold in the spring auction, 0 otherwise; and

Month = the following values:

January	=	0
February	=	-0.0201
March	=	0
April	=	0
May	=	0.8181
June	=	0.2835
July	=	0.5201
August	=	0.7221
September	=	0
October	=	0.32
November	=	-0.7681
December	=	0

Provided, however, for purposes of determining the credit holding requirement for a Fixed Price TCC, the market clearing price shall be replaced by the fixed price associated with

that Fixed Price TCC, as determined in Section 19.2.1 or Section 19.2.2, of Attachment M as appropriate, of the OATT.

Further, when calculating “Pijt” in Section 26.4.2.4.1, in the event there is no market clearing price for a two-year, one-year, six-month, or one-month TCC in the appropriate prior Capability Period Centralized TCC Auction with the same POI and POW combination as the awarded two-year, one-year, six-month, or one-month TCC, as appropriate, then the market clearing price shall equal a proxy price, assigned by the ISO, for a TCC with like characteristics.

Further, the NYISO may adjust any of the Zone K multipliers in Section 26.4.2.4.1 if, for TCCs of the same duration, the percentage ratio between collateral and congestion rents for Zone K TCCs deviates from the percentage ratio for Zone J TCCs by more than ten percent (10.0%).

26.4.2.4.2 Mark-to-Market Calculation

The projected amount of the Primary Holder’s payment obligation to the NYISO, if any, considering the net mark-to-market value of all TCCs in the Primary Holder’s portfolio, as defined for these purposes, according to the formula below:

$$\sum_{n \in N} \left\{ \frac{NAP_n}{90} \times RD_n \right\} + \sum ACR_n$$

where:

NAP = the net amount of Congestion Rents between the POI and POW composing each TCC_n during the previous ninety days

RD = the remaining number of days in the life of TCC_n; *provided, however*, that in the case of Grandfathered TCCs, RD shall equal the remaining number of days in the life of the longest duration TCC sold in an ISO-administered auction then outstanding;

N = the set of TCCs held by the Primary Holder; and

ACR = the net amount owed to the ISO for Congestion Rents between the POI and POW composing each TCC_n.

26.4.2.5 WTSC Component

The WTSC Component shall be equal to the greater of either:

$$\frac{\text{Greatest Amount Owed for WTSC During Any Single Month in the Prior Equivalent Capability Period}}{\text{Days in Month}} \times 50$$

- or -

$$\frac{\text{Total Charges Incurred for WTSC Based Upon the Most Recent Monthly Data Provided by the Transmission Owner}}{\text{Days in Month}} \times 50$$

26.4.2.6 Virtual Transaction Component

The Virtual Transaction Component shall be equal to the sum of the Customer's

(i) Virtual Supply credit requirement ("VSCR") for all outstanding Virtual Supply Bids, plus (ii) Virtual Load credit requirement ("VLCR") for all outstanding Virtual Load Bids, plus (iii) net amount owed to the ISO for settled Virtual Transactions.

Where:

$$\text{VSCR} = \sum (\text{VSG}_{\text{MWh}} \times \text{VSG}_{\text{CS}})$$

$$\text{VLCR} = \sum (\text{VLG}_{\text{MWh}} \times \text{VLG}_{\text{CS}})$$

Where:

VSG_{MWh} = the total quantity of MWhs of Virtual Supply that a Customer Bids for all Virtual Supply positions in the Virtual Supply group

VSG_{CS} = the amount of credit support required in \$/MWh for the Virtual Supply group

VLG_{MWh} = the total quantity of MWhs of Virtual Load that a Customer Bids for all Virtual Load positions in the Virtual Load group

VLG_{CS} = the amount of credit support required in \$/MWh for the Virtual Load group

The ISO will categorize each Virtual Supply Bid into one of the 72 Virtual Supply groups set forth in the Virtual Supply chart below, as appropriate, based upon the season, Load Zone,

and time-of-day of the Virtual Supply Bid. The amount of credit support required in \$/MWh for a Virtual Transaction in a particular Virtual Supply group shall equal the price differential between the Energy price in the Day-Ahead Market and the Energy price in the Real-Time Market, at the 97th percentile, based upon all possible Virtual Supply positions in the Virtual Supply group for the period of time from April 1, 2005, through the end of the preceding calendar month.

The ISO will categorize each Virtual Load Bid into one of the 30 Virtual Load groups set forth in the Virtual Load chart below, as appropriate, based upon the season, Load Zone, and time-of-day of the Virtual Load Bid. The amount of credit support required in \$/MWh for a Virtual Transaction in a particular Virtual Load group shall equal the price differential between the Energy price in the Day-Ahead Market and the Energy price in the Real-Time Market, at the 97th percentile, based upon all possible Virtual Load positions in the Virtual Load group for the period of time from April 1, 2005, through the end of the preceding calendar month.

If a Customer submits Bids for both Virtual Load and Virtual Supply for the same day, hour, and Load Zone, then for those Bids, until such time as those Bids have been evaluated by SCUC, only the greater of the Customer's (i) VLCR for the total MWhs Bid for Virtual Load, or (ii) VSCR for the total MWhs Bid for Virtual Supply will be included when calculating the Customer's Virtual Transaction Component. After evaluation of those Bids by SCUC, then only the credit requirement for the net position of the accepted Bids (in MWhs of Virtual Load or Virtual Supply) will be included when calculating the Customer's Virtual Transaction Component.

Virtual Supply Groups

Summer	Load Zones A–F	Load Zones G–I	Load Zone J	Load Zone K
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HB07–10	VSG-1	VSG-7	VSG-13	VSG-19
HB11–14	VSG-2	VSG-8	VSG-14	VSG-20
HB15–18	VSG-3	VSG-9	VSG-15	VSG-21
HB19–22	VSG-4	VSG-10	VSG-16	VSG-22
Weekend/ Holiday (HB07–22)	VSG-5	VSG-11	VSG-17	VSG-23
Night (HB23–06)	VSG-6	VSG-12	VSG-18	VSG-24
Winter				
HB07–10	VSG-25	VSG-31	VSG-37	VSG-43
HB11–14	VSG-26	VSG-32	VSG-38	VSG-44
HB15–18	VSG-27	VSG-33	VSG-39	VSG-45
HB19–22	VSG-28	VSG-34	VSG-40	VSG-46
Weekend/ Holiday (HB07–22)	VSG-29	VSG-35	VSG-41	VSG-47
Night (HB23–06)	VSG-30	VSG-36	VSG-42	VSG-48
Rest-of-Year				
HB07–10	VSG-49	VSG-55	VSG-61	VSG-67
HB11–14	VSG-50	VSG-56	VSG-62	VSG-68
HB15–18	VSG-51	VSG-57	VSG-63	VSG-69
HB19–22	VSG-52	VSG-58	VSG-64	VSG-70
Weekend/ Holiday (HB07–22)	VSG-53	VSG-59	VSG-65	VSG-71
Night (HB23–06)	VSG-54	VSG-60	VSG-66	VSG-72

Where:

Summer	=	May, June, July, and August
Winter	=	December, January, and February
Rest-of-Year	=	March, April, September, October, and November
HB07–10	=	weekday hours beginning 07:00–10:00
HB11–14	=	weekday hours beginning 11:00–14:00
HB15–18	=	weekday hours beginning 15:00–18:00
HB19–22	=	weekday hours beginning 19:00– 22:00
Weekend/Holiday	=	weekend and holiday hours beginning 07:00–22:00
Night	=	all hours beginning 23:00– 06:00

Virtual Load Groups

Summer	Load Zones A–F	Load Zones G–I	Load Zone J	Load Zone K
HB07–10	VLG-1	VLG-4	VLG-8	VLG-12

HB11–14	VLG-2	VLG-5	VLG-9	VLG-13
HB15–18	VLG-2	VLG-6	VLG-10	VLG-14
HB19–22	VLG-1	VLG-4	VLG-8	VLG-15
Weekend/ Holiday (HB07–22)	VLG-3	VLG-4	VLG-8	VLG-16
Night (HB23–06)	VLG-1	VLG-7	VLG-11	VLG-12
Winter				
HB07–10	VLG-17	VLG-19	VLG-21	VLG-23
HB11–14	VLG-17	VLG-20	VLG-21	VLG-23
HB15–18	VLG-18	VLG-19	VLG-22	VLG-24
HB19–22	VLG-17	VLG-20	VLG-21	VLG-24
Weekend/ Holiday (HB07–22)	VLG-17	VLG-20	VLG-21	VLG-23
Night (HB23–06)	VLG-17	VLG-20	VLG-21	VLG-23
Rest-of-Year				
HB07–10	VLG-25	VLG-26	VLG-27	VLG-29
HB11–14	VLG-25	VLG-26	VLG-28	VLG-29
HB15–18	VLG-25	VLG-26	VLG-28	VLG-30
HB19–22	VLG-25	VLG-26	VLG-27	VLG-30
Weekend/ Holiday (HB07–22)	VLG-25	VLG-26	VLG-27	VLG-30
Night (HB23–06)	VLG-25	VLG-26	VLG-27	VLG-29

Where:

Summer	=	May, June, July, and August
Winter	=	December, January, and February
Rest-of-Year	=	March, April, September, October, and November
HB07–10	=	weekday hours beginning 07:00–10:00
HB11–14	=	weekday hours beginning 11:00–14:00
HB15–18	=	weekday hours beginning 15:00–18:00
HB19–22	=	weekday hours beginning 19:00– 22:00
Weekend/Holiday	=	weekend and holiday hours beginning 07:00–22:00
Night	=	all hours beginning 23:00– 06:00

26.4.2.7 DADRP Component

The DADRP Component shall be equal to the product of: (i) the Demand Reduction Provider's monthly average of MWh of accepted Demand Reduction Bids during the prior summer Capability Period or, where the Demand Reduction Provider does not have a history of

accepted Demand Reduction bids, a projected monthly average of the Demand Reduction Provider's accepted Demand Reduction bids; (ii) the average Day-Ahead LBMP at the NYISO Reference Bus during the prior summer Capability Period; (iii) twenty percent (20%); and (iv) a factor of four (4). The ISO shall adjust the amount of Unsecured Credit and/or collateral that a Demand Reduction Provider is required to provide whenever the DADRP Component increases or decreases by ten percent (10%) or more.

26.4.2.8 DSASP Component

The DSASP Component is calculated every two months based on the Demand Side Resource's Operating Capacity available for the scheduling of such services, the delta between the Day-Ahead and hourly market clearing prices for such products in the like two-month period of the previous year, and the location of the Demand Side Resource. Resources located East of Central-East shall pay the Eastern reserves credit support requirement and Resources located West of Central-East shall pay the Western reserves credit support requirement. The DSASP Component shall be equal to:

- (a) For Demand Side Resources eligible to offer only Operating Reserves, the product of (i) the maximum hourly Operating Capacity (MW) for which the Demand Side Resource may be scheduled to provide Operating Reserves, (ii) the amount of Eastern or Western reserves credit support, as appropriate, in \$/MW per day, and (iii) three (3) days.

Where:

The amount of Eastern reserves credit support (\$/MW/day) for each two-month period	=	Eastern Price Differential for the same two-month period in the previous year * the higher of two (2) or the maximum number of daily Reserve Activations for the same two-month period in the previous year
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The amount of Western reserves credit support (\$/MW/day) for each two-month period	=	Western Price Differential for the same two-month period in the previous year * the higher of two (2) or the maximum number of daily Reserve Activations for the same two-month period in the previous year
Two-month periods:	=	January and February March and April May and June July and August September and October November and December
MCP_{SRh}	=	Hourly, time-weighted Market Clearing Price for Spinning Reserves
Eastern Price Differential	=	The hourly differential at the 97 th percentile of all hourly differentials between the Day-Ahead and Real-Time MCPSRh for Eastern Spinning Reserves for hours in the two-month period of the previous year when the Real-Time MCPSRh for Eastern Spinning Reserves exceeded the Day-Ahead MCPSRh for Eastern Spinning Reserves
Western Price Differential	=	The hourly differential at the 97 th percentile of all hourly differentials between the Day-Ahead and Real-Time MCPsSRh for Western Spinning Reserves for hours in the two-month period of the previous year when the Real-Time MCPSRh for Western Spinning Reserves exceeded the Day-Ahead MCPSRh for Western Spinning Reserves
Reserve Activations	=	The number of reserve activations at the 97 th percentile of daily reserve activations for days in each two month period of the previous year that had reserve activations.

- (b) For Demand Side Resources eligible to offer only Regulation Service, or Operating Reserves and Regulation Service, the product of (i) the maximum hourly Operating Capacity (MW) for which the Demand Side Resource may be scheduled to provide Regulation Service and Operating Reserves, (ii) the amount

of regulation credit support, as appropriate, in \$/MW per day, and (iii) three (3) days.

Where:

The amount of regulation credit support (\$/MW/day) for each two-month period	=	Price Differential for the same two-month period in the previous year * 24 hours
Two-month periods:	=	January and February March and April May and June July and August September and October November and December
MCP_{RegH}	=	Hourly, time-weighted Market Clearing Price for Regulation Services
Price Differential	=	The hourly differential at the 97 th percentile of all hourly differentials between the Day-Ahead and Hour-Ahead MCP_{RegH} for hours in the two-month period of the previous year when the Real-Time MCP exceeded the Day-Ahead MCP

26.4.3 Calculation of Bidding Requirement

The Bidding Requirement shall be an amount equal to the sum of:

- (i) the amount of bidding or nominating authorization that the Customer has requested for use in or during, as appropriate, an upcoming ISO-administered TCC auction, which shall account for all positive bids or nominations to purchase TCCs and the absolute value of all negative offers to sell TCCs; *provided, however,* that the amount of credit required for each TCC that the Customer bids or nominates to purchase, whether positive, negative, or zero shall not be less than (a) (2 x \$/MW for one-year TCCs) per MW for two-year TCCs, (b) \$1,500 per

MW for one-year TCCs, (c) \$2,000 per MW for six-month TCCs, and (d) \$600 per MW for one-month TCCs;

- (ii) the approximate amount that the Customer may owe following an upcoming TCC auction as a result of converting expired ETAs into Historic Fixed Price TCCs pursuant to Section 19.2.1 of Attachment M to the OATT, which shall be calculated in accordance with the provisions of Section 19.2.1 regarding the purchase of TCCs with a duration of ten years;
- (iii) the amount of bidding authorization that the Customer has requested for use in an upcoming ISO-administered ICAP auction; and
- (iv) five (5) days prior to any ICAP Spot Market Auction, the amount that the Customer may be required to pay for UCAP in the auction, calculated as follows:

$$\sum_{L \in S} \left[\begin{aligned} &ICPM_L \times 1000 \times Deficiency_L \\ &+ \\ &ICPM_L \times 1000 \times \frac{(ZCP_L - 1) \times RQT_L}{2} \end{aligned} \right]$$

Where:

S equals a set containing the following locations: each Locality and Rest of State,

L equals a location in the set S ,

$ICPM_L$ equals the lesser of $UBRP_L$ or LM_L ,

$UBRP_L$ equals the UCAP based reference point (in \$/kW-Month) for location L , as determined on the ICAP Demand Curve for that location (or for NYCA, if L is Rest of State) for the applicable Obligation Procurement Period,

LM_L equals (1) for any Locality L that is contained within another Locality X , the greater of CPM_L or CPM_X , or (2) for any other Locality or Rest of State, CPM_L ,

CPM_L	equals for location L , $(1 + Margin_L) * MCP_L$,
CPM_X	equals for location X , $(1 + Margin_X) * MCP_X$,
$Margin_L$	equals 25% if location L is New York City and 100% if location L is G-J Locality, Long Island or Rest of State,
MCP_L	equals the Market-Clearing Price for location L in the most recent Monthly Auction that established such a price for the month covered by the ICAP Spot Market Auction, measured in dollars per kilowatt-month,
$Deficiency_L$	equals the number of megawatts of Unforced Capacity that are to be procured in location L on behalf of that Customer in the ICAP Spot Market Auction in order to cover any deficiency for that Customer that exists in that location after the certification deadline for that ICAP Spot Market Auction less any deficiency calculated for that Customer for any Localities contained within location L , such value not to be less than zero,
ZCP_L	equals the percentage determined in accordance with Services Tariff Section 5.14.1.2 for the applicable ICAP Demand Curves as established at the \$0.00 point for the appropriate Capability Year, and
RQT_L	equals (1) if L is New York City or Long Island, that Customer's share of the Locational Minimum Unforced Capacity Requirement for location L or (2) if L is G-J Locality, that Customer's share of the Locational Minimum Unforced Capacity Requirement for the G-J Locality that remains after reducing this amount by its share of the Locational Minimum Unforced Capacity Requirements for New York City or, (3) if L is Rest of State, that Customer's share of the NYCA Minimum Unforced Capacity Requirement that remains after reducing this amount by (a) its share of the Locational Minimum Unforced Capacity Requirements for New York City and Long Island and (b) that Customer's share of the Locational Minimum Unforced Capacity Requirement for the G-J Locality remaining after accounting for New York City, as calculated in (2) above; such value not to be less than zero.