Attachment XIII

1.1 Definitions - A

Accepted Revision: A change to the terms of an Existing Transmission Agreement for purposes of ISO Settlements, which change is related to a Grandfathered Right or Grandfathered TCC and is made pursuant to the procedures prescribed in Section 17 Attachment K of the ISO OATT.

Actual Demand Reductions: As defined in the ISO Services Tariff.

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

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

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

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

Aggregation: As defined in the ISO Services Tariff.

Aggregator: As defined in the ISO Services Tariff.

Ancillary Services: Those services that are necessary to support the transmission of Capacity and Energy from resources to Loads while maintaining reliable operation of the NYS Transmission System in accordance with Good Utility Practice.

Annual Transmission Costs: The total annual cost of the Transmission System for purposes of Network Integration and Point-to-Point Transmission Services shall be the amount specified in Attachment H until amended by the Transmission Owners or modified by the Commission.

Annual Transmission Revenue Requirement: The total annual cost for each Transmission Owner (other than LIPA) to provide transmission service subject to review and acceptance by FERC or other authority.

Application: A request to receive Transmission Service by an Eligible Customer pursuant to the provisions of this Tariff that includes all information reasonably requested by the ISO.

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

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

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

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

Available Transfer Capability ("ATC"): A measure of the Transfer Capability remaining in the physical transmission network for further commercial activity, over and above already committed uses, calculated using the methodology described in Attachment C in the OATT.

1.2 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 2.12 of this ISO OATT and Section 5.3 of the ISO Services Tariff.

Balance-of-Period Auction: An auction administered by the ISO in which Transmission Customers may purchase and sell TCCs valid for a future month or months in the same Capability Period in which the auction is conducted; provided, however, that the Balance-of-Period Auction conducted in the last month of a Capability Period will allow for the purchase and sale of TCCs valid for a future month or months in the next Capability Period.

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

Basis Amount: As defined in the ISO Services Tariff.

Behind-the-Meter Net Generation Resource ("BTM:NG Resource"): As defined in the ISO Services Tariff.

Basis Month: As defined in the ISO Services Tariff.

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 Locational Based Marginal Prices 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 mitigated Bid where appropriate.

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

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

Bidding Requirement: As defined in the ISO 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 2.7.3.2.1, or 2.7.3.2.2 of this ISO OATT over which the ISO will aggregate and settle a charge or a payment for services furnished under this ISO OATT or the ISO Services Tariff.

Board of Directors ("Board"): The governing body of the ISO which is comprised of ten (10) persons (Directors) that are unaffiliated with any Market Participants, as described in the ISO Agreement.

Business Issues Committee: A standing committee of the ISO created pursuant to the ISO Agreement to establish rules related to business issues and provide a forum for discussion of those rules and issues.

1.3 Definitions - C

Capability Period: Six-month periods which are established as follows: (1) from May 1 through October 31 of each year ("Summer Capability Period"); and (2) from November 1 of each year through April 30 of the following year ("Winter Capability Period"); or such other periods as may be determined by the Operating Committee of the ISO. A Summer Capability Period followed by a Winter Capability Period shall be referred to as a "Capability Year". Each Capability Period shall consist of On-Peak and Off-Peak periods.

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

Capacity Benefit Margin ("CBM"): That amount of Total Transfer Capability reserved by the ISO on the NYS Transmission System to ensure access to generation from interconnected systems to meet generation reliability requirements.

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 Member System'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.

Centralized TCC Auction: The auction in which TCCs are released for sale for one or more Capability Periods through a bidding process administered by the ISO.

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.

Commenced Repair: As defined in the ISO Services Tariff.

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

Completed Application: An Application that satisfies all of the information and other requirements of the Tariff.

Confidential Information: Information and/or data which has been designated by a Transmission Customer to be proprietary and confidential, provided that such designation is consistent with the ISO Procedures and this Tariff, including the attached 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 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 Tariff 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 Systems.

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.

Contract Establishment Date: The date, listed in Attachment L, on which the listed existing agreements which are the source of Grandfathered Rights and Grandfathered TCCs were executed.

Control Area: An electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

(1) match, at all times, the power output of the Generators and Aggregations within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the Load within the electric power system(s);

(2) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

(3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and

(4) provide sufficient capacity to maintain Operating Reserves in accordance with Good Utility Practice.

Credible Repair Plan: As defined in the ISO Services Tariff.

Credit Assessment: As defined in the ISO 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.

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

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 ISO Services Tariff pursuant to an unsigned Service Agreement filed with the Commission by the ISO shall be deemed a Customer.

1.4 Definitions - D

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

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

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

Day-Ahead Reliability Unit: A Day-Ahead committed Resource which would not have been committed but for the commitment request by a Transmission Owner to the ISO in order to meet the reliability needs of the Transmission Owner's local system which request was made known to the ISO prior to the close of the Day-Ahead Market.

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

Demand Side Resource: As defined in the ISO Services Tariff.

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

Dependable Maximum Gross Capability ("DMGC"): As defined in the ISO Services Tariff.

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

DER Aggregation: As defined in the ISO Services Tariff.

Designated Agent: Any entity that performs actions or functions on behalf of the Transmission Owner, an Eligible Customer, or the Transmission Customer required under the Tariff.

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

Developer: An Eligible Customer developing a generation project larger than 20 megawatts, or a Class Year Transmission Project, proposing to interconnect to the New York State Transmission System, in compliance with the NYISO Minimum Interconnection Standard and, depending on the Developer's interconnection service election, also in compliance with the NYISO Deliverability Interconnection Standard.

Direct Assignment Facilities: Facilities or portions of facilities that are constructed by the Transmission Owner(s) for the sole use/benefit of a particular Transmission Customer requesting service under the ISO OATT. Direct Assignment Facilities shall be specified in the Service Agreement that governs service to the Transmission Customer and shall be subject to Commission approval.

Direct Sale: The sale of Original Residual TCCs, ETCNL, and Grandfathered TCCs directly to a buyer by the Transmission Owner that is the Primary Holder through a non-discriminatory auditable sale conducted on the ISO's OASIS, in compliance with the requirements and restrictions set forth in Commission Orders 888 et seq. and 889 et seq.

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

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

Distributed Energy Resource ("DER"): As defined in the ISO Services Tariff.

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

1.5 Definitions - E

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

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

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

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

Eligible Customer: (i) An entity that is engaged, or proposes to engage, in the wholesale or retail electric power business including any electric utility, power marketer, Federal power marketing agency, or any person generating Energy for sale for resale is an Eligible Customer under the Tariff. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by Section 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that the Transmission Owner offer the unbundled Transmission Service, or pursuant to a voluntary offer of such service by the Transmission Owner. (ii) Any retail customer taking unbundled transmission service pursuant to a state requirement that the Transmission Owner offer the transmission service, or pursuant to a voluntary offer of such service by the Transmission Owner, is an Eligible Customer under the Tariff.

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

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

Transmission System or Generators that could adversely affect the reliability of the NYS Power System.

End-State Centralized TCC Auction: A Centralized TCC Auction that the ISO will conduct after the ISO develops the necessary software.

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

Energy and Ancillary Services Component: As defined in the ISO Services Tariff.

Energy Duration Limitation: As defined in the ISO Services Tariff.

Energy Storage Resource: As defined in the ISO Services Tariff.

Equivalency Rating: As defined in the ISO Services Tariff.

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

ETCNL TCC: A TCC created when a Transmission Owner with ETCNL exercises its right to convert a megawatt of ETCNL into a TCC pursuant to Section 19.4.1 of Attachment M of this ISO OATT.

Excess Congestion Rents: Congestion revenues in the Day-Ahead Market for Energy collected by the ISO that are in excess of its Day-Ahead payment obligations. Excess Congestion Rents may arise if Congestion occurs in the Day- Ahead Market for Energy and if the Day-Ahead Transfer Capability of the Transmission System is not exhausted by the set of already-outstanding TCCs and Grandfathered Rights that are valid.

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

Existing Transmission Capacity for Native Load ("ETCNL"): Transmission capacity identified on a Transmission Owner's transmission system to serve the Native Load customers of the current Transmission Owners (as of the filing date of the original ISO Tariff-January 31, 1997) for the purposes of allocating revenues from the sale of TCCs related to that capacity. This includes transmission capacity required: (1) to deliver the output from Generators located out of a Transmission Owner's Transmission District; (2) to deliver power purchased under power supply contracts; and (3) to deliver power purchased under third party agreements (i.e., Non-Utility Generators). Existing Transmission Capacity for Native Load is listed in Attachment L, Table 3, “Existing Transmission Capacity Reservations for Native Load Table.”

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

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

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

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

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

1.9 Definitions - I

ICAP Ineligible Forced Outage: As defined in the ISO Services Tariff.

Import Curtailment Guarantee Payment: A payment made in accordance with Section 4.5.3.2 and Attachment J of the 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 Revenue: The Congestion Rents that owners of Grandfathered Rights do not have to pay due to their own use of those Grandfathered Rights.

Inactive Reserves: As defined in the ISO Services Tariff.

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.

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 this ISO OATT.

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

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

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

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

Injection Billing Units: A Transmission Customer's Actual Energy Injections (for all internal injections) or Scheduled Energy Injections (for all Import Energy injections) in the New York Control Area, including injections for Wheels Through. For purposes of Rate Schedule 1 and Rate Schedule 11 of this ISO OATT, (i) a Limited Energy Storage Resource shall be responsible for charges or eligible for payments on the basis only of its Actual Energy Injections and (ii) Demand Reduction by a DER Aggregation shall be included as Injection Billing Units. For purposes of recovering the ISO annual budgeted costs and the annual FERC fee pursuant to Rate Schedule 1 of this ISO OATT, Injection Billing Units shall include the absolute value of negative injections by Withdrawal-Eligible Generators.

Injection Limit: As defined in the ISO Services Tariff.

Installed Capacity: A Generator or Load facility that complies with the requirements in the Reliability Rules and is capable of supplying and/or reducing the demand for Energy in the NYCA for the purpose of ensuring that sufficient Energy and Capacity are available to meet the Reliability Rules. The Installed Capacity requirement, established by the NYSRC, includes a margin of reserve in accordance with the Reliability Rules.

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.

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

Intermittent Power Resource: A device for the production of electricity that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by the 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, or 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: As defined in the ISO 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 administered by the ISO.

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

ISO-Committed Flexible: A bidding mode in which a Dispatchable Generator or Aggregation comprised entirely of Energy Storage Resources follows Base Point Signals and is committed by the ISO. BTM:NG Resources and Aggregations that are not entirely comprised of ESRs are not permitted to utilize the ISO-Committed Flexible bidding mode.

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

ISO OATT (the "Tariff"): 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 NYSRC Agreement, the ISO/NYSRC Agreement, the ISO/TO Agreement, and Operating Agreements.

NYISO Services Tariff: The ISO Market Administration and Control Area Services Tariff.

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

1.12 Definitions - L

LBMP Markets: A term that collectively refers to both the Real-Time Market and the Day-Ahead Market.

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

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

Load: A term that refers to either a consumer of Energy or the amount of Energy (MWh) or demand (MW) consumed by certain consumers.

Load Ratio Share: The ratio of an LSE's Load to Load within the NYCA during a specified time period.

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

Load Shedding: The systematic reduction of system demand by temporarily decreasing Load in response to Transmission System or area Capacity shortages, system instability, or voltage control considerations under Part 4 of the Tariff.

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

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

Locality: Shall have the meaning set forth in §2.12 of the ISO Services Tariff.

Local Generator: Shall have the meaning set forth in §2.12 of the ISO Services Tariff.

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

Locational Based Marginal Pricing ("LBMP"): The price of Energy at each location in the NYS Transmission System as calculated pursuant to Attachment J.

Locational Minimum Installed Capacity Requirement: The determination by the ISO in accordance with the ISO Services Tariff of that portion of the NYCA Minimum Installed Capacity Requirement (as defined in the ISO Services Tariff) that must be electrically located within a Locality.

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

Long-Term Firm Point-To-Point Transmission Service: Firm Point-to-Point Service, the price of which is fixed for a long term by a Transmission Customer acquiring sufficient TCCs with the same Points of Receipt and Delivery as its Transmission Service.

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

1.13 Definitions - M

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

Manual Dispatch: A dispatch of the NYS Transmission System performed by the ISO when the ISO's RTD is unavailable.

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

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

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

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

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

Meter Services Entity ("MSE"): As defined in the ISO Services Tariff.

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

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

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

Mothball Outage: As defined in the ISO Services Tariff.

1.14 Definitions - N

Native Load Customers: The wholesale and retail power customers of the Transmission Owners on whose behalf the Transmission Owners, by statute, franchise, regulatory requirement, or contract, have undertaken an obligation to construct and operate the Transmission Owners' systems to meet the reliable electric needs of such customers.

Neptune Scheduled Line: A transmission facility that interconnects the NYCA to the PJM Interconnection LLC Control Area at Levittown, Town of Hempstead, New York and terminates in Sayerville, New Jersey.

NERC: The North American Electric Reliability Council or, as applicable, the North American Electric Reliability Corporation.

NERC Transaction Priorities: The reservation and scheduling priority applied to a Transaction under the NERC Transmission Loading Relief Procedure.

NERC Transmission Loading Relief ("TLR") Procedure: "Standard IRO-006-3 – Reliability Coordination – Transmission Loading Relief" as approved in Docket No. ER06-1545, and any amendments thereto. See www.nerc.com for the current version of the NERC TLR Procedure.

Net Auction Revenue: The total amount, in dollars, as calculated pursuant to Section 20.3.1 of Attachment N, remaining after collection of all charges and allocation of all payments associated with a round of a Centralized TCC Auction or a Reconfiguration Auction. Net Auction Revenue takes into account: (i) revenues from and payments for the award of TCCs in a Centralized TCC Auction or Reconfiguration Auction, (ii) payments to Transmission Owners releasing ETCNL, (iii) payments or charges to Primary Holders selling TCCs, (iv) payments to Transmission Owners releasing Original Residual TCCs, (v) O/R-t-S Auction Revenue Surplus Payments and U/D Auction Revenue Surplus Payments, and (vi) O/R-t-S Auction Revenue Shortfall Charges and U/D Auction Revenue Shortfall Charges. Net Auction Revenue may be positive or negative.

Net Congestion Rent: The total amount, in dollars, as calculated pursuant to Section 20.2.1 of Attachment N, remaining after collection of all Congestion-related charges and allocation of all Congestion-related payments associated with the Day-Ahead Market. Net Congestion Rent takes into account: (i) charges and payments for Congestion Rents, (ii) settlements with TCC Primary Holders, (iii) O/R-t-S Congestion Rent Shortfall Charges and U/D Congestion Rent Shortfall Charges, and (iv) O/R-t-S Rent Congestion Surplus Payments and U/D Congestion Rent Surplus Payments. Net Congestion Rent may be positive or negative.

Net Installed Capacity ("Net-ICAP"): As defined in the ISO Services Tariff.

Net Unforced Capacity ("Net-UCAP"): As defined in the ISO Services Tariff.

Network Customer: An entity receiving Transmission Service pursuant to the terms of the ISO's Network Integration Transmission Service under Part 4 of the Tariff.

Network Integration Transmission Service: The Transmission Service provided under Part 4 of the Tariff.

Network Load: The Load that a Network Customer designates for Network Integration Transmission Service under Part 4 of the Tariff. The Network Customer's Network Load shall include all Load served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total Load as Network Load but may not designate only part of the Load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular Load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Part 3 of the Tariff for any Point-To-Point Transmission Service that may be necessary for such non-designated Load.

Network Operating Agreement: An executed agreement that contains the terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Network Integration Transmission Service under Part 4 of the Tariff. For Eligible Customers that take service under the ISO Services Tariff, that Tariff shall function as their Network Operating Agreement.

Network Operating Committee: The ISO Operating Committee will serve this function.

Network Resource: Any generating resource that provides Installed Capacity to the NYCA designated under the Network Integration Transmission Service provisions of the Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a reserve sharing program.

Network Upgrades: Modifications or additions to transmission facilities that are integrated with and support the Transmission Owner's overall Transmission System for the general benefit of all users of such Transmission System.

Network Upgrade Agreement: An agreement entered into between a Transmission Customer and a Transmission Owner that identifies the rights and obligations of each party with respect to the Network Upgrade, as described in this Tariff.

New York City: The electrical area comprised of Load Zone J, as identified in the ISO Procedures.

New York Control Area ("NYCA"): The Control Area that is under the control of the ISO which includes transmission facilities listed in the ISO/TO Agreement Appendices A-1 and A-2, as amended from time-to-time, and Generation located outside the NYS Power System that is subject to protocols (e.g., telemetry signal biasing) which allow the ISO and other Control Area operator(s) to treat some or all of that Generation as though it were part of the NYS Power System.

New York Power Pool ("NYPP"): An organization established by agreement (the "New York Power Pool Agreement") made as of July 21, 1966, and amended as of July 16, 1991, by and among Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., Long Island Lighting Company, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation, Orange and Rockland Utilities, Inc., Rochester Gas and Electric Corporation, and the Power Authority of the State of New York. LIPA became a Member of the NYPP on May 28, 1998 as a result of the acquisition of the Long Island Lighting Company by the Long Island Power Authority.

New York State Bulk Power Transmission Facility: This term shall have the meaning given in Attachment Y to the OATT.

New York State Power System ("NYS Power System"): All facilities of the NYS Transmission System, and all those Generators and Aggregations located within the NYCA or outside the NYCA, some of which may from time-to-time be subject to operational control by the ISO.

New York State Reliability Council ("NYSRC"): An organization established by agreement among the Member Systems of the New York Power Pool (the "NYSRC Agreement").

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

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

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

Non-Investment Grade Customer: As defined in the ISO Services Tariff.

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

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

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

Notice of Intent to Return: As defined in the ISO Services Tariff.

Notification: Informing the ISO of all changes in status of the Transmission Facilities Requiring ISO Notification. Notification includes the Transmission Owners informing the ISO of all changes in the status of the designated transmission facilities.

Nuclear Regulatory Commission ("NRC"): Nuclear Regulatory Commission, or any successor thereto.

NYPA: The Power Authority of the State of New York.

NYPA Transmission Adjustment Charge ("NTAC"): A surcharge on all Energy Transactions designed to recover the Annual Transmission Revenue Requirement of NYPA which cannot be recovered through its TSC, TCCs, or other transmission revenues, including, but not limited to, its ETA revenues. This charge will be assessed to all Load statewide, as well as Transmission Customers in Wheels Through and Exports.

1.16 Definitions - P

Part 1: Tariff Section 1 pertaining to Definitions.

Part 2: Tariff Section 2 pertaining to Common Service Provisions.

Part 3: Tariff Section 3 pertaining to Point-To-Point Transmission Service in conjunction with the applicable Common Service Provisions of Part 2 and appropriate Schedules and Attachments.

Part 4: Tariff Section 4 pertaining to Network Integration Transmission Service in conjunction with the applicable Common Service Provisions of Part 2 and appropriate Schedules and Attachments.

Part 5: OATT Section 5 – Special Provisions for retail access and the Individual Retail Access Plans

Party or Parties: The ISO and the Transmission Customer receiving service under the Tariff.

Peak Load Window: As defined in the ISO Services Tariff.

Performance Tracking System: A system designed to report metrics for Generators, Aggregations, and Loads which include but are not limited to actual output and schedules (See Rate Schedule 3 of the ISO Services Tariff). This system is used by the ISO to measure compliance with criteria associated with the provision of Energy and Ancillary Services.

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 ISO Tariffs. The Point(s) of Delivery shall be specified in the Bid, Bilateral Transaction schedule, or similar entry.

Point(s) of Injection ("POI"): The point(s) on the NYS Transmission System or Proxy Generator Buses where Energy and Ancillary Services will be made available to the ISO by the Customer or Transmission Customer under the ISO Tariffs. The Point(s) of Injection shall be specified in the Bid, Bilateral Transaction schedule, or similar entry. (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 ISO Tariffs. The Point(s) of Receipt shall be specified in the Bid, Bilateral Transaction schedule, or similar entry.

Point(s) of Withdrawal ("POW"): The point(s) on the NYS Transmission System or Proxy Generator Buses where Energy will be made available to the Transmission Customer or Customer under the ISO Tariffs. The Point(s) of Withdrawal shall be specified in the Bid, Bilateral Transaction Schedule, or other similar entry. (May be referred to as "Point of Delivery" or similar in some Existing Transmission Agreements.)

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.

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, Capacity and/or Ancillary Services in the 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.

Power Purchaser: The entity that is purchasing the Capacity and Energy to be transmitted under the Tariff.

Primary Holder: The Transmission Customer that is the recognized holder of a TCC, as described in Attachment M of this ISO OATT.

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

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 available 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, N.Y. Pub. Serv. Law § 1 et seq. (McKinney 1989 & Supp. 1997-98).

1.17 Definitions - Q

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

1.18 Definitions - R

RCRR TCC: A Load Zone-to-Load Zone TCC created when a Member System with a RCRR exercises its right to convert the RCRR into a TCC pursuant to Section 19.5.4 of Attachment M of this ISO OATT.

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

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

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

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

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

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

Services Tariff the term "RTD" will normally be used to refer to both the Real-Time Dispatch and to the specialized Real-Time Dispatch Corrective Action Mode software.

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

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

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

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

Reconfiguration Auction: The monthly auction administered by the ISO which will either be: (i) a Balance-of-Period Auction; or (ii) an auction in which Transmission Customers may purchase and sell one-month TCCs; provided, however, that the ISO shall only conduct one Reconfiguration Auction type in a month.

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

Regional Transmission Group (RTG): A voluntary organization of transmission owners, transmission users and other entities approved by the Commission to efficiently coordinate transmission planning (and expansion), operation and use on a regional (and interregional) basis.

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

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

Repair Plan: As defined in the ISO Services Tariff.

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

Reserved Capacity: The maximum amount of Capacity and Energy that the ISO agrees to transmit for the Transmission Customer over the NYS Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part 3 of this Tariff. Reserved Capacity shall be expressed in terms of whole megawatts on a sixty (60) minute interval (commencing on the clock hour) basis.

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

Residual Capacity Reservation Right ("RCRR"): A megawatt of transmission capacity from one Load Zone to an electrically contiguous Load Zone, each of which is internal to the NYCA, that may be converted into an RCRR TCC by a Member System allocated the RCRR pursuant to Section 19.5 of Attachment M.

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

Residual Transmission Capacity = TTC - TRM - CBM - GTR - GTCC - ETCNL

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

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

GTR is the transmission capacity associated with Grandfathered Rights.

GTCC is the transmission capacity associated with Grandfathered TCCs.

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

TRM is the Transmission Reliability Margin.

CBM is the Capacity Benefit Margin.

Resource with Energy Duration Limitation: As defined in the ISO Services Tariff.

Retired: As defined in the ISO Services Tariff.

RMR Agreement: An agreement of limited duration that provides for the continued operation of one or more RMR Generator(s) to satisfy one or more Generator Deactivation Reliability Need(s) entered into between the ISO and an entity or entities that own or have operational control over the RMR Generator(s).

RMR Avoidable Costs: The (a) fixed costs of an Initiating Generator that would be avoided if it were to exit the ISO-Administered Markets in the manner specified in its Generator Deactivation Notice, (b) the fixed costs of a Generator already in a Mothball Outage, an ICAP Ineligible Forced Outage, or that has been mothballed since before May 1, 2015 that would be incurred if it were to re-enter the ISO-Administered Markets pursuant to an RMR Agreement that would be avoided if it remained in such state, or (c) the costs necessary for a new Generator proposed as a Generator Deactivation Solution to enter service. RMR Avoidable Costs include mandatory capital expenditures, fixed operating and maintenance costs, and forgone opportunity costs, determined by the ISO in accordance with Section 38.8 of Attachment FF, as modified by the Commission. RMR Avoidable Costs do not include variable costs or any other type of cost that are included in the Generator's Energy or Ancillary Services reference levels, or that are ordinarily included in Energy or Ancillary Services reference levels.

RMR Generator: The Generator or Generators operating under an RMR Agreement.

Rolling RTC: The RTC run that is used to schedule a given 15-minute External Transaction. The Rolling RTC may be an RTC_{00}, RTC_{15}, RTC_{30} or RTC_{45} run.

1.19 Definitions - S

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

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

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

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

Scheduled Energy Injection: Energy injections or Energy provided by Demand Side Resources which are scheduled on a real-time basis by RTC.

Scheduled Energy Withdrawal: Energy Withdrawals which are scheduled on a real-time basis by RTC.

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

SCUC: Security Constrained Unit Commitment, described in Attachment C of the Tariff.

Second Contingency Design and Operation: The planning, design and operation of a power system such that the loss of any two (2) facilities will not result in a service interruption to either native load customers or contracted firm Transmission Customers. Second Contingency Design and Operation criteria do not include the simultaneous loss of two (2) facilities, but rather consider the loss of one (1) facility and the restoration of the system to within acceptable operating parameters, prior to the loss of a second facility. These criteria apply to thermal, voltage and stability limits and are generally equal to or more stringent than NYPP, NPCC and NERC criteria.

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

Secondary Holder: Entities that purchase TCCs and have not been certified as a Primary Holder by the ISO.

Secondary Market: A market in which Primary and Secondary Holders sell TCCs by mechanisms other than through the Centralized TCC Auction, Reconfiguration Auction, or by Direct Sale.

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

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

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

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

Service Agreement: The initial agreement and any amendments or supplements thereto entered into by the Transmission Customer and the ISO for service under the Tariff or any unexecuted Service Agreement, amendments on supplements thereto, that the ISO unilaterally files with the Commission.

Service Commencement Date: The date the ISO begins to provide service pursuant to the terms of an executed Service Agreement, or the date the ISO begins to provide service in accordance with Section 3.3.3 or Section 4.2.1 under the Tariff.

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

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

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

Short-Term Firm Point-To-Point Transmission Service: Firm Point-to-Point Service, the price of which is fixed for a short term by a Transmission Customer acquiring sufficient TCCs with the same Points of Receipt and Delivery as its Transmission Service.

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

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

Special Test Transactions: The revenues or costs from purchases and/or sales of Energy that may occur pursuant to virtual regional dispatch/intra-hour transaction pilot tests conducted by the ISO to analyze potential solutions for, or approaches to resolving inter-market "seams" issues with neighboring control area operators.

Start-Up Bid: A Bid parameter that may vary hourly and that identifies the payment a Supplier requires to bring a Generator up to its specified minimum operating level from an offline state. If the Supplier is a BTM:NG Resource, Energy Storage Resource or an Aggregation, it shall not submit a Start-Up Bid.

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

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

Strandable Costs: Prudent and verifiable expenditures and commitments made pursuant to a Transmission Owner's legal obligations that are currently recovered in the Transmission Owner's retail or wholesale rate that could become unrecoverable as a result of a restructuring of the electric utility industry and/or electricity market, or as a result of retail-turned-wholesale customers, or customers switching generation or transmission service suppliers.

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

Sub-Auctions: The set of rounds in a given Centralized TCC Auction in which TCCs of a given duration may be purchased.

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

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

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

Supplemental Resource Evaluation ("SRE"): A determination of the least cost selection of additional Generators or Aggregations, which are to be committed, to meet: (i) changed or local system conditions for the Dispatch Day that may cause the Day-Ahead schedules for the Dispatch Day to be inadequate to meet the reliability requirements of the Transmission Owner's local system or to meet Load or reliability requirements of the ISO; or (ii) forecast Load and reserve requirements over the six-day period that follows the Dispatch Day.

System Impact Study: An assessment by the ISO of (i) the adequacy of the NYS Transmission System to accommodate a request to build facilities in order to create incremental transfer capability, resulting in incremental TCCs, in connection with a request for either Firm Point-To-Point Transmission Service or Network Integration Transmission Service; and (ii) the additional costs to be incurred in order to provide the incremental transfer capability.

1.20 Definitions - T

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

Third Party Sale: Any sale for resale in interstate commerce to a power purchaser that is not designated as part of Network Load under the Network Integration Transmission Service.

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

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

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

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

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

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

Transmission Congestion Contract Component ("TCC Component"): As defined in the ISO Services Tariff.

Transmission Congestion Contracts ("TCCs"): The right to collect or obligation to pay Congestion Rents in the Day-Ahead Market for Energy associated with a single MW of transmission between a specified POI and POW. TCCs are financial instruments that enable Energy buyers and sellers to hedge fluctuations in the price of transmission.

Transmission Customer: Any Eligible Customer (or its designated agent) that (i) executes a Service Agreement, or (ii) requests in writing that the ISO file with the Commission a proposed unexecuted Service Agreement to receive Transmission Service under Part 3, 4 and/or 5 of the Tariff.

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

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

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

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

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

Transmission Node: As defined in the ISO Services Tariff.

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

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

Transmission Plan: A plan developed by the ISO staff with Transmission Owner's support that is a compilation of transmission projects proposed by the Transmission Owners and others, that are found to meet all applicable criteria.

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

Transmission Service: Point-To-Point, Network Integration or Retail Access Transmission Service provided under Parts 3, 4 and 5 of the Tariff.

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

Transmission Shortage Cost: As defined in the NYISO Services Tariff.

Transmission System: The facilities operated by the ISO that are used to provide Transmission Services under Part 3, Part 4 or Part 5 of this Tariff.

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

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

1.23 Definitions - W

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

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

Withdrawal-Eligible Generator: As defined in the ISO Services Tariff.

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

Wholesale Transmission Services Charges ("WTSC"): Those charges calculated pursuant to Attachment H of the OATT, incurred or declared overdue by a Transmission Owner pursuant to Section 26.11.2 of Attachment K to the ISO Services Tariff, after the effective date of these revisions; provided, however, that these provisions will not apply to pre-petition bankruptcy debts for a company that is currently in bankruptcy.

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

Withdrawal Billing Units: A Transmission Customer's Actual Energy Withdrawals (for all internal withdrawals) or Scheduled Energy Withdrawals (for all Export Energy withdrawals), including withdrawals for Wheels Through.

WTSC Component: As defined in the ISO Services Tariff.

2.7 Billing and Payment

2.7.1 ISO as Counterparty; Right to Net or Set Off; ISO Clearing Account

2.7.1.1 ISO as Counterparty

The ISO shall be for all purposes the contracting counterparty, in its own name and right, to each Transmission Customer for any purchase or sale of any product or service, or for any other transaction, that is financially settled by the ISO under the ISO Tariffs.

2.7.1.2 Right to Net or Set Off Obligations Owed

Unless otherwise specifically set forth in this ISO OATT, if for any settlement period the ISO is required to pay any amount to the Transmission Customer and the Transmission Customer is required to pay any amount to the ISO under this ISO OATT or the ISO Services Tariff, such amounts shall be netted, and the party owing the greater aggregate amount shall pay to the other party the difference between the amounts owed. Additionally, all outstanding payment obligations under this ISO OATT and the ISO Services Tariff between the ISO and the Transmission Customer may be netted, offset, set off, or recouped, and payment shall be owed as set forth above.

2.7.1.3 ISO Clearing Account

The ISO will establish one or more accounts (the "ISO Clearing Account") at a bank or other financial institution, and Transmission Customers shall make payments to the ISO or receive payments from the ISO through the ISO Clearing Account in accordance with their settlement information provided by the ISO as described in Section 2.7.3 of this ISO OATT.

The funds held by the ISO in the ISO Clearing Account shall not be commingled with funds held by the ISO in any other ISO accounts.

2.7.1.4 ISO Liability for Payment

The obligation of the ISO to pay Transmission Customers for monies owed for a given settlement period shall be limited so that the aggregate liability of the ISO for such payments does not exceed the sum of (i) the aggregate amount paid to or recovered by the ISO from Transmission Customers (including by applying a defaulting Transmission Customer's financial security) for that settlement period, and (ii) the amount of funds held by the ISO in the Working Capital Fund. The process for declaring and recovering bad debt losses is set forth in Attachment U to this ISO OATT.

2.7.2 Determination and Payment of Charges Associated with Transmission Service

This Section 2.7.2 applies to all Transmission Services except Transmission Service pursuant to Grandfathered Agreements listed in Attachment L. Charges applicable to Grandfathered Agreements are described in Attachment K.

2.7.2.1 Transmission Service Charge - General Applicability

The TSC charge is applied to all Actual Energy Withdrawals from the NYS Power System under Part 3 or Part 4 of this Tariff, except for withdrawals by a Transmission Owner to provide bundled retail service or scheduled withdrawals associated with grandfathered transactions as specified in Attachments K and L. The TSC charge also is applied to Transactions to destinations outside the NYCA (Export or Wheel-Through Transactions), except as provided for in Section 2.7.2.1.4 of this Tariff.

Subject to the foregoing, the TSC applies to all Actual Energy Withdrawals regardless of whether the withdrawals occur in conjunction with a Bilateral Transaction or through the purchase of Energy from an LBMP Market. The TSC is payable under this Section regardless of whether the withdrawal is scheduled under Part 3 or Part 4 of this Tariff. Customers buying Energy from a Transmission Owner as part of a bundled retail rate will pay a portion of the Transmission Owner's transmission revenue requirement as part of their retail rates. Sales to these customers will be included in the billing units used to calculate each Transmission Owner's TSC under this Tariff in accordance with Attachment H.

Transmission Customers who are parties to grandfathered agreements specified in Attachment L will pay the applicable contract rate in those agreements. Revenues from these agreements will be credited against the Transmission Owners' individual revenue requirements in calculating the TSC.

2.7.2.1.1 Payable to Transmission Owners: The TSC will be payable to Transmission Owners, in the manner described below in the remainder of Section 2.7.2.1.

2.7.2.1.2 Payable by Retail Access Customers: Retail access customers or LSEs scheduling on their behalf will pay a TSC to their respective Transmission Owners under the provisions described in Part 5 of this Tariff. The TSC is payable under Part 5 (Retail Access Service) regardless of whether the LSE takes service under Part 3 (Point-to-Point Service) or Part 4 (Network Integration Service) of this Tariff.

2.7.2.1.3 Payable by LSEs Serving Non-Retail Access Load in NYCA: LSEs serving NYCA Load that is not part of a retail access program, such as customers of municipal electric systems, will pay a TSC to the Transmission Owner in whose Transmission District the Load is located. The TSC shall apply to Actual Energy Withdrawals by the Load, regardless of whether such withdrawals are associated with Transmission Service under Part 3 or Part 4 of this Tariff or purchases from an LBMP Market, whether the withdrawals are scheduled or unscheduled, and regardless of whether the withdrawals were made on the Load's behalf by the LSE or by another Transmission Customer.

2.7.2.1.4 Payable by Transmission Customers Scheduling Export or Wheel-Through Transactions: Transmission Customers scheduling Transactions to destinations outside the NYCA (Export or Wheel-Through Transactions) are subject to a TSC as calculated in Attachment H. The TSC charge shall be eliminated on all Exports and Wheel-Through Transactions scheduled with the ISO to destinations within the New England Control Area; provided that the following conditions shall continue to be met: (1) a Commission approved tariff provision is in effect that provides for unconditional reciprocal elimination of charges on Exports and Wheel-Through Transactions from the New England Control Area to the New York Control Area; (2) no change in the provisions in this Tariff related to Local Furnishing Bonds and Other Tax Exempt Financing shall be required for the reciprocal elimination of charges on Export and Wheel-Through Transactions to the New York Control Area; and (3) the New York Transmission Owners have the ability to fully recover the revenues related to the charges on Export and Wheel-Through Transactions that are eliminated. The ISO and the New York Transmission Owners, jointly or separately, shall have the right to make a Section 205 filing with the Commission to reimpose the charge on Exports and Wheel-Through Transactions if at any time any of the foregoing conditions is no longer satisfied. The ISO will perform the requisite calculation and inform the Transmission Customer of the applicable Transmission Owner(s) of the TSC charge. The TSC will be payable by the Transmission Customer directly to the Transmission Owner(s).

2.7.2.2 Transmission Usage Charge (TUC)

2.7.2.2.1 Payable to the ISO: Transmission Usage Charges include Congestion Rents and charges for Marginal Losses. They are payable directly to the ISO. Attachment J explains the calculation of the TUC.

2.7.2.2.2 Payable by Transmission Customers Scheduling Transmission Service: All Transmission Customers scheduling Transmission Service under Part 3 or Part 4 of this Tariff shall pay the applicable TUC charge as calculated in the Attachment J hereto.

2.7.2.2.3 Payable by Transmission Owners Scheduling Bilateral Transactions on Behalf of Bundled Retail Customers: Transmission Owners scheduling Transmission Service to supply bundled retail customers shall pay the applicable TUC charge.

2.7.2.2.4 Payable by Customers Scheduling Direct LBMP Purchases from the LBMP Market: Any Customer purchasing from the LBMP Market to supply bundled retail customers, will pay the Congestion Rent and Marginal Losses charge applicable to its location. These Congestion Rent and Marginal Losses charges will be included in the calculation of the LBMP charged by the ISO for the purchase of Energy from the LBMP Market.

2.7.2.3 Ancillary Services

2.7.2.3.1 Payable to the ISO: All Ancillary Services charges are payable directly to the ISO.

2.7.2.3.2 Payable by LSEs: All LSEs scheduling Transmission Service under Part 3 or Part 4 or purchases from the LMBP Market to supply Load in the NYCA shall pay Ancillary Services charges as described in Schedules 1 through 6. The charges will be assessed on the basis of all Actual Energy Withdrawals by the Load, regardless of whether such withdrawals are scheduled or unscheduled, and regardless of whether they are scheduled on the Load's behalf by the LSE or by another Transmission Customer. As explained in Schedule 1, in certain circumstances the Schedule 1 charge may vary depending upon the Transmission District in which the Load is located.

2.7.2.3.3 Payable by Customers Scheduling External Transactions: Transmission Customers scheduling Export or Wheel-Through Transactions to destinations outside the NYCA, or purchases from the LBMP Market to serve Load outside the NYCA shall pay Ancillary Services charges under Schedules 1, 2, 4, and 5 of this Tariff. The charges will be assessed on the basis of all Scheduled Energy Withdrawals from the NYCA.

2.7.2.3.4 Payable by Transmission Owners Serving Bundled Retail Customers: Transmission Owners scheduling Transmission Service or purchases from the LBMP Market to serve of bundled retail customers shall pay the ISO Ancillary Services charges as described in Schedules 1 to 6 based on Actual Energy Withdrawals.

2.7.2.4 NYPA Transmission Adjustment Charge (NTAC)

2.7.2.4.1 Payable to the ISO: NTAC charges are calculated in Attachment H. All NTAC charges are payable to the ISO.

2.7.2.4.2 Payable by LSEs Serving Load in the NYCA: Each LSE serving Load in the NYCA shall pay an NTAC to the ISO based on the LSE's Actual Energy Withdrawals.

2.7.2.4.3 Payable by Transmission Customers Scheduling Export or Wheel-Through Transactions: Transmission Customers scheduling Export or Wheel-Through Transactions shall pay an NTAC based on their Transaction schedules. The NTAC charge shall not apply to Exports and Wheel-Through Transactions scheduled with the ISO to destinations within the New England Control Area provided that the conditions listed in Section 2.7.2.1.4 of this Tariff are satisfied.

2.7.2.5 Reliability Facilities Charge ("RFC") and LIPA RFC

2.7.2.5.1 Payable through the ISO: All RFC and LIPA RFC charges are calculated, collected and payable to the ISO pursuant to Rate Schedule 10.

2.7.3 Billing and Payment Procedures

For purposes of this Section 2.7.3:

(i) the term "Complete Week Settlement Period" shall mean the seven day period between Saturday and Friday for which all of the days are in the same month; and

(ii) the term "Stub Week Settlement Period" shall mean the six or fewer day period between Saturday and Friday for which all of the days are in the same month.

2.7.3.1 Billing and Settlement Information

The ISO shall provide settlement and billing information to Transmission Customers. The ISO shall inform each Transmission Customer that provides or is provided services furnished under this ISO OATT or the ISO Services Tariff of the payments due for such service. Such information shall be made electronically available to the Transmission Customer.

2.7.3.2 Invoicing and Payment

2.7.3.2.1 Weekly Invoice

On or about each Wednesday, as set forth in ISO Procedures, the ISO shall submit an invoice to a Transmission Customer that indicates the net amount owed by or owed to the Transmission Customer for those services furnished under this ISO OATT or the ISO Services Tariff for the previous Complete Week Settlement Period or Stub Week Settlement Period that are designated as Weekly Invoice Components in ISO Procedures; *provided, however,* that the net amount owed by or owed to the Transmission Customer for those services furnished for a Stub Week Settlement Period that concludes a month shall be included in the next monthly invoice issued in accordance with Section 2.7.3.2.2 of this ISO OATT.

2.7.3.2.2 Monthly Invoice

Within five (5) business days after the first day of each month, the ISO shall submit an invoice to a Transmission Customer that indicates the net amount owed by or owed to the Transmission Customer:

(i) for those services furnished under this ISO OATT or the ISO Services Tariff for a Stub Week Settlement Period that concludes the previous month that are designated as Weekly Invoice Components in ISO Procedures;

(ii) for any adjustments to amounts contained in the weekly invoices issued in the previous month pursuant to Section 2.7.3.2.1 of this ISO OATT;

(iii) for those services furnished under this ISO OATT or the ISO Services Tariff in the previous month that are designated as Monthly Invoice Components in ISO Procedures;

(iv) for any adjustments to amounts contained in a previously issued monthly invoice that was issued on or about one hundred twenty (120) days prior to the issuance of this invoice; and

(v) for any adjustments to amounts contained in a previously issued monthly invoice as part of the Close-Out Settlement of that monthly invoice pursuant to Section 2.7.4.2.2 of this ISO OATT.

2.7.3.2.3 Payment by the Transmission Customer

A Transmission Customer owing payments on net in its weekly invoice or its monthly invoice shall make those payments to the ISO through the ISO Clearing Account by the second business day after the date on which the weekly invoice or monthly invoice is rendered by the ISO unless otherwise specified in ISO Procedures. In accordance with Section 2.7.1.2 of this

ISO OATT, the ISO may net any overpayment by the Transmission Customer for past estimated charges against current amounts due from the Transmission Customer or, if the Transmission Customer has no outstanding amounts due, the ISO may pay to the Transmission Customer an amount equal to the overpayment.

2.7.3.2.4 Payment by the ISO

Except as provided in Section 2.7.1.4 of this ISO OATT, the ISO shall pay all net monies owed to a Transmission Customer in its weekly invoice or its monthly invoice from the ISO Clearing Account by the second business day after the due date for Transmission Customer payments set forth in Section 2.7.3.2.3 of this ISO OATT unless otherwise specified in ISO Procedures.

2.7.3.3 Use of Estimated Data and Meter Data

The ISO may use estimates, including estimated meter data, in whole or in part to settle a weekly or monthly invoice in accordance with ISO Procedures. The ISO shall use meter data submitted to the ISO in accordance with Section 3.16 of this ISO OATT. Any charges based on estimates shall be subject to true-up in invoices subsequently issued by the ISO after the ISO has obtained the requisite actual information, provided that the ISO shall only true-up charges based on meter data prior to the deadline for finalizing the meter data established in Section 2.7.4.2 of this ISO OATT. A trued-up charge shall include interest amounts calculated at the rate set forth in Section 2.7.4 of this ISO OATT from the weekly or monthly due date for the charge until the date of payment of the trued-up amount for that charge.

2.7.3.4 Method of Payment

All payments by the Transmission Customer shall be made by either (i) wire transfer in immediately available funds payable to the ISO through the ISO Clearing Account or (ii) any other method set forth in ISO Procedures. All payments by the ISO shall be made either (i) by wire transfer in immediately available funds payable to the Transmission Customer by the ISO through the ISO Clearing Account or (ii) any other method set forth in ISO Procedures.

2.7.3.5 Verification of Payments

The ISO shall verify that all payments owed by Transmission Customers in accordance with this ISO OATT and the ISO Services Tariff have been paid to the ISO in a timely manner. If a Transmission Customer fails to make a payment within the time period established in Sections 2.7.3.2.1, 2.7.3.2.2, and 2.7.3.6 of this ISO OATT or pays less than the amount due, the ISO shall take measures pursuant to Section 2.7.5 of this ISO OATT. Except as provided in Section 2.7.1.4 of this ISO OATT, the ISO shall also ensure that monies owed to Transmission Customers in accordance with this ISO OATT and the ISO Services Tariff are paid through the ISO Clearing Account in a timely manner.

2.7.3.6 TCC Auction Settlements

Notwithstanding Sections 2.7.3.2.1 and 2.7.3.2.2 of this ISO OATT, the ISO shall make settlements related to the Centralized TCC Auction and the Reconfiguration Auction as set forth in this Section 2.7.3.6.

2.7.3.6.1 The ISO shall submit invoices to, and make settlements with, Transmission Owners in connection with the allocation of Net Auction Revenues in accordance with the timeline set forth in ISO Procedures.

2.7.3.6.2 Transmission Customers owing payments to the ISO as a result of their activity in or related to a Centralized TCC Auction or Reconfiguration Auction, pursuant to an award notice or a comparable invoice rendered by the ISO, shall make those payments to the ISO through the ISO Clearing Account in accordance with the timeline set forth in ISO Procedures.

2.7.3.6.3 Except as provided in Section 2.7.1.4 of this ISO OATT, the ISO shall pay all net monies owed to Transmission Customers as a result of their activity in or related to a Centralized TCC Auction or a Reconfiguration Auction, pursuant to an award notice or a comparable invoice rendered by the ISO, from the ISO Clearing Account in accordance with ISO Procedures.

2.7.3.6.4 Sections 2.7.3.1, 2.7.3.3, 2.7.3.4 and 2.7.3.5 of this ISO OATT and Section 19.9.6 of Attachment M of this ISO OATT shall apply to settlements calculated in accordance with this Section 2.7.3.6.

2.7.3.7 Settlement Information and Billing Procedures for TSCs

The ISO shall provide each Member System with information to facilitate TSC billing. Settlement information and billing procedures for payments of the TSC by retail access customers or LSEs serving retail access customers in accordance with Section 5 of this ISO OATT shall be separately issued, paid and collected in accordance with Section 5 of this ISO OATT. Settlement information and billing procedures for payments for TSCs for customers other than retail access customers and LSEs serving retail access customers shall be separately issued, paid and collected in accordance with the terms and conditions set forth in Attachment H of this ISO OATT in accordance with Section 5 of this ISO OATT.

2.7.3.8 Billing Procedures for Retail Access Programs

The billing procedures for customers participating in retail access programs shall be in accordance with Section 5 of this ISO OATT.

2.7.4 Interest on Unpaid Balances:

Interest on any unpaid amount whether owed to a Transmission Customer or to the ISO (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a (a)-(2)(iii). Interest on unpaid amounts shall be calculated from the due date of the bill to the date of payment. Invoices shall be considered as having been paid on the date of receipt of payment by the ISO.

If the ISO is unable to provide settlement information on time due to the actions or inactions of the Transmission Customer, in addition to any other remedies the ISO may have at law or in equity, the Transmission Customer shall pay interest on amounts due, as calculated above, from the first day of the Billing Period following the Billing Period in which charges are accrued, to the time of payment of those charges.

2.7.4.1 Billing Disputes:

This Section 2.7.4.1 establishes the process and timeframe for review, challenge, and correction of Transmission Customer invoices. For purposes of this Section 2.7.4.1, any deadline that falls on a Saturday, Sunday, or holiday for which the ISO is closed shall be observed on the ISO's next business day.

For purposes of this Section 2.7.4.1, "finalized" data and invoices shall not be subject to further correction, including by the ISO, except as ordered by the Commission or a court of competent jurisdiction; *provided, however*, that nothing herein shall be construed to restrict any stakeholder's right to seek redress from the Commission in accordance with the Federal Power Act.

2.7.4.2 Settlement Cycle for Services Furnished On and After January 1, 2009

2.7.4.2.1 ISO Corrections or Adjustments and Transmission Customer Challenges to the Accuracy of Settlement Information

Settlement information for services furnished beginning January 1, 2009, and thereafter shall be subject to review, comment, and challenge by a Transmission Customer and correction or adjustment by the ISO for errors at any time for up to five (5) months from the date of the initial invoice for the month in which service is rendered as set forth in Section 2.7.3.2.2 of this ISO OATT and as further provided in Section 2.7.4.2.2, subject to the following requirements and limitations:

(i) A Supplier or meter authority may review, comment on, and challenge Aggregation, Generator, tie-line, and sub-zone Load metering data for fifty-five (55) days from the date of the initial invoice for the month in which service is rendered. Following this review period, the ISO shall then have five (5) days to process and correct Aggregation, Generator, tie-line, and sub-zone Load metering data, after which time it shall be finalized.

(ii) The meter authority shall provide to the ISO all LSE bus metering data then available within seventy (70) days from the date of the initial invoice and shall provide any necessary updates to the LSE bus metering data as soon as possible thereafter. The ISO shall post all available LSE bus metering data within approximately seventy-five (75) days from the date of the initial invoice and shall continue to post incoming LSE bus metering data as soon as practicable after it is received.

(iii) The ISO shall post advisory settlement information, including available LSE bus metering data, within ninety (90) days from the date of the initial invoice. Transmission Customers may review, comment on, and challenge this settlement information, except for Aggregation, Generator, tie-line, and sub-zone Load metering data, after which the ISO shall process and correct the data and issue a corrected invoice with the regular monthly invoice issued on or about one hundred twenty (120) days from the date of the initial invoice. Following the ISO's issuance of a corrected invoice, Transmission Customers may continue to review, comment on, and challenge their settlement information, excepting Aggregation, Generator, tie-line, and sub-zone Load metering data, until the end of the five-month review period.

(iv) The meter authority shall provide to the ISO any final updates or corrections to LSE bus metering data within one hundred thirty (130) days from the date of the initial invoice. The ISO shall then post any updated and corrected LSE bus metering data within one hundred thirty-five (135) days from the date of the initial invoice. Transmission Customers may then review, comment on, and challenge the LSE bus metering data for an additional ten (10) days. Following this review period, the ISO shall have five (5) days to process and correct the LSE bus metering data, after which it shall be finalized.

The ISO shall use reasonable means to post metering revisions for review by Transmission Customers and to notify Transmission Customers of the approaching expiration of review periods. To challenge settlement information contained in an invoice, a Transmission Customer shall first make payment in full, including any amounts in dispute. Transmission

Customer challenges to settlement information shall: (i) be submitted to the ISO in writing, (ii) be clearly identified as a settlement challenge, (iii) state the basis for the Transmission Customer's challenge, and (iv) include supporting documentation, if applicable. The ISO shall notify all Transmission Customers of errors identified and the details of corrections or adjustments made pursuant to this Section 2.7.4.2.1.

2.7.4.2.2 Review and Correction of Challenged Invoices

The ISO shall evaluate a settlement challenge as soon as possible within two (2) months following the conclusion of the challenge period specified in Section 2.7.4.2.1; *provided, however,* the ISO may, upon notice to Transmission Customers within this time of extraordinary circumstances requiring a longer evaluation period, take up to six (6) months to evaluate a settlement challenge. The ISO shall not be limited to the scope of Transmission Customer challenges in its review of a challenged invoice and may, at its discretion, review and correct any other elements and intervals of a challenged invoice, except Load and meter data as specified in Section 2.7.4.2.1. Corrections to a challenged invoice shall be applied to all Transmission Customers that were or should have been affected by the original settlement and shall not be limited to the Transmission Customer challenging the invoice; *provided, however,* that the ISO may recover *de minimis* amounts or amounts that the ISO is unable to collect from individual Transmission Customers through Rate Schedule 1 of this ISO OATT.

Upon completing its evaluation, the ISO shall provide written notice to the challenging Transmission Customer of the ISO's final determination regarding the Transmission Customer's settlement challenge. If the ISO determines that corrections or adjustments to a challenged invoice are necessary and can quantify them with reasonable certainty, the ISO shall provide all Transmission Customers with the details of the corrections or adjustments within the timeframe established in this Section 2.7.4.2.2. The ISO shall then provide a period of twenty-five (25) days for Transmission Customers to review the corrected settlement information and provide comments to the ISO regarding the implementation of those corrections or adjustments; *provided, however,* that in the event of a dispute resolution proceeding conducted in accordance with Section 2.7.4.3 of this ISO OATT, this twenty-five (25) day period shall not start or, if it has already started, shall be suspended until the conclusion of the dispute resolution proceeding. Following the conclusion of the dispute resolution proceeding, the ISO shall make any corrections to Transmission Customers' settlement invoices that it determines to be necessary and shall then start or re-start the twenty-five (25) day Transmission Customer comment period.

If no errors in the implementation of corrections or adjustments are identified during the twenty-five (25) day Transmission Customer comment period, the ISO shall issue a finalized close-out settlement ("Close-Out Settlement"), clearly identified as such, in the next regular monthly billing invoice. If an error in the implementation of a correction or adjustment is identified during the twenty-five (25) day Transmission Customer comment period, the ISO shall have one (1) month to make such further corrections as are necessary to address the error and provide Transmission Customers with one additional period of twenty-five (25) days to review and comment on the implementation of those further corrections. If an error in the implementation of those further corrections is identified, the ISO shall then have one (1) month to make any final corrections that are necessary and shall issue a finalized Close-Out Settlement in the next regular monthly billing invoice.

2.7.4.3 Expedited Dispute Resolution Procedures for Unresolved Settlement Challenges

2.7.4.3.1 Applicability of Expedited Dispute Resolution Procedures

This Section 2.7.4.3 establishes expedited dispute resolution procedures applicable to address any dispute between a Transmission Customer and the ISO regarding a Transmission Customer settlement that was not resolved in the ordinary settlement review, challenge, and correction process; *provided*, *however*, that nothing herein shall restrict a Transmission Customer or the ISO from seeking redress from the Commission in accordance with the Federal Power Act.

A Transmission Customer may request expedited dispute resolution if it has previously presented a settlement challenge consistent with the requirements of Section 2.7.4.2.1 of this ISO OATT and has received from the ISO a final, written determination regarding the settlement challenge pursuant to Section 2.7.4.2.2 of this ISO OATT. The scope of an expedited dispute resolution proceeding shall be limited to the subject matter of the Transmission Customer's prior settlement challenge. Transmission Customer challenges regarding Aggregation, Generator, tie-line, sub-zone Load, and LSE bus metering data shall not be eligible for formal dispute resolution proceedings under this ISO OATT. To ensure consistent treatment of disputes, separate requests for expedited dispute resolution regarding the same issue and the same service month or months may be resolved on a consolidated basis, consistent with applicable confidentiality requirements.

2.7.4.3.2 Initiation of Expedited Dispute Resolution Proceeding

To initiate an expedited dispute resolution proceeding, a Transmission Customer shall submit a written request to the ISO Chief Financial Officer within eleven (11) business days from the date that the ISO issues a final, written determination regarding a Transmission Customer settlement challenge pursuant to Section 2.7.4.2.2 of this ISO OATT. A Transmission

Customer's written request for expedited dispute resolution shall contain: (i) the name of the Transmission Customer making the request, (ii) an indication of other potentially affected parties, to the extent known, (iii) an estimate of the amount in controversy, (iv) a description of the Transmission Customer's claim with sufficient detail to enable the ISO to determine whether the claim is within the subject matter of a settlement challenge previously submitted by the Transmission Customer, (v) copies of the settlement challenge materials previously submitted by the Transmission Customer to the ISO, and (vi) citations to the ISO Tariffs and other relevant materials upon which the Transmission Customer's settlement challenge relies.

The ISO Chief Financial Officer shall acknowledge in writing receipt of the Transmission Customer's request to initiate an expedited dispute resolution proceeding. If the ISO determines that the proceeding would be likely to aid in the resolution of the dispute, the ISO shall accept the Transmission Customer's request and provide written notice of the proceeding to all Transmission Customers through the ordinary means of communication for settlement issues. The ISO shall provide written notice to the Transmission Customer in the event that the ISO declines its request for expedited dispute resolution.

2.7.4.3.3 Participation by Other Interested Transmission Customers

Any Transmission Customer with rights or interests that would be materially affected by the outcome of an expedited dispute resolution proceeding may participate; *provided, however,* that a Transmission Customer seeking or supporting a change to the NYISO's determination regarding a Transmission Customer settlement challenge must have previously raised the issue in a settlement challenge consistent with the requirements of Section 2.7.4.2.1 of this ISO OATT. To participate, such Transmission Customer shall submit to the ISO Chief Financial Officer a written request to participate that meets the requirements for an initiating request for expedited dispute resolution within eleven (11) business days from the date that the ISO issues notice of the expedited dispute resolution proceeding. If the ISO determines that the Transmission Customer has met the requirements of this Section 2.7.4.3.3, the ISO will accept the Transmission Customer's request to participate in the dispute resolution proceeding.

2.7.4.3.4 Selection of a Neutral

As soon as reasonably possible following the ISO's acceptance of a Transmission Customer's request for expedited dispute resolution under Section 2.7.4.3.2, the ISO shall appoint a neutral to preside over the proceeding by randomly selecting from a list (i) provided to the ISO by the American Arbitration Association or (ii) developed by the ISO with input from the appropriate stakeholder committee, until an available neutral is found. To the extent possible, the neutral shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues and the financial settlement of electric markets.

No person shall be eligible to act as a neutral who is a past or present officer, employee, or consultant to any of the disputing parties, or of an entity related to or affiliated with any of the disputing parties, or is otherwise interested in the matter in dispute except upon the express written consent of the parties. Any individual appointed as a neutral shall make known to the disputing parties any such disqualifying relationship or interest and a new neutral shall be appointed, unless express written consent is provided by each party.

2.7.4.3.5 Conduct of the Expedited Dispute Resolution Proceeding

The neutral shall schedule the initial meeting of the disputing parties within five (5) business days of appointment. Except as otherwise provided in this Section 2.7.4.3, the neutral shall have discretion over the conduct of the dispute resolution process including, but not limited to: (i) requiring the disputing parties to meet for discussion, (ii) allowing or requiring written submissions, (iii) establishing guidelines for such written submissions, and (iv) allowing the participation of Transmission Customers that have requested an opportunity to be heard.

Within sixty (60) days of the appointment of the neutral, if the dispute has not been resolved, the neutral shall provide the disputing parties with a written, confidential, and non-binding recommendation for resolving the dispute. The disputing parties shall then meet in an attempt to resolve the dispute in light of the neutral's recommendation. If the disputing parties have not resolved the dispute within ten (10) days of receipt of the neutral's recommendation, the dispute resolution process will be concluded.

Neither the recommendation of the neutral, nor statements made by the neutral or any party, including the ISO, or their representatives, nor written submissions prepared for the dispute resolution process, shall be admissible for any purpose in any proceeding.

2.7.4.3.6 Allocation of Costs

Each party to a dispute resolution proceeding shall be responsible for its own costs incurred during the process and for a pro rata share of the costs of a neutral.

2.7.5 Customer Default

2.7.5.1 Events of Default

A Transmission Customer shall be in default, upon written notice from the ISO, in the event that: (i) the Transmission Customer fails to timely make a payment due to the ISO, regardless of whether such payment obligation is in dispute, (ii) the Transmission Customer fails to comply with the ISO's creditworthiness requirements, or (iii) the Transmission Customer fails to cure its default in another independent system operator/regional transmission organization market. In the event of a billing dispute between the ISO and the Transmission Customer, the

ISO will continue to provide service under the Service Agreement as long as the Transmission Customer continues to make all payments.

2.7.5.2 Cure

Unless otherwise provided in Attachment W to this OATT, a Transmission Customer shall have one (1) business day to cure a default resulting from its failure to timely make a payment due to the ISO. A Transmission Customer shall have two (2) business days to cure a default resulting from its failure to comply with the ISO's creditworthiness requirements; *provided, however,* that a Transmission Customer shall have one (1) business day to cure a default resulting from its failure to comply with the ISO's creditworthiness requirements following termination of a Prepayment Agreement.

2.7.5.3 ISO Remedies

In addition to any and all other remedies available under the ISO Tariffs or pursuant to law or equity, the ISO shall have the following remedies:

(i) **Event of Default.** Upon an event of default and expiration of the relevant cure period, the ISO may terminate service to a Transmission Customer immediately upon notice to the Commission. In addition, in the event of a payment default, the ISO shall have the sole and exclusive right to initiate debt collection procedures against a Transmission Customer on account of any such default. The process for declaring and recovering bad debt losses is set forth in Attachment U to this OATT.

(ii) **Financial Distress.** In the event of a reduction in the amount of a Transmission Customer's Unsecured Credit (a) by fifty percent (50%) or more as determined in accordance with Section 26.5 of Attachment K to the ISO Services Tariff, or (b) as a result of a material adverse change as determined in accordance with Section 26.14 of Attachment K to the ISO Services Tariff, then the ISO shall have the right to: (1) immediately issue an invoice to such Transmission Customer requiring payment within two (2) business days from the invoice date for initial settlements representing the sum of that Billing Period's daily billing data available as of the invoice date, and/or (2) require such Transmission Customer to prepay estimated charges weekly for up to twelve months in accordance with ISO Procedures.

(iii) **Default in Another ISO/RTO.** In the event a Transmission Customer fails to cure its default in another independent system operator/regional transmission organization market, then the ISO shall have the right to: (1) demand immediate payment by the Transmission Customer to the ISO for any amounts owed as of the date of the demand, and/or (2) require the Transmission Customer to prepay estimated charges weekly for a minimum of twelve months in accordance with ISO Procedures, and/or (3) reduce or eliminate the amount of the Transmission Customer's Unsecured Credit.

(iv) **Two Late Payments.** In the event a Transmission Customer fails to pay its invoice when due on two occasions within a rolling twelve (12) month period, then the ISO shall have the right to: (1) require the Transmission Customer to prepay estimated charges weekly, based on the charges incurred by the Transmission Customer in the previous week, for up to twelve months, and/or (2) reduce or eliminate the amount of the Transmission Customer's Unsecured Credit for up to twelve (12) months.

2.7.5.4 Notice to Transmission Customers

The ISO shall notify all Transmission Customers in the event that a Transmission Customer is in default and shall also notify all Transmission Customers in the event that the Transmission Customer subsequently cures the default or the ISO terminates the Transmission Customer due to the default. In the event of a payment default or creditworthiness default, the ISO will disclose in its notice to Transmission Customers the approximate amount of the default as follows:

Default Amount	Type of Default	
Range	Payment	Creditworthiness
$0 to $100,000		
$100,001 to $500,000		
$500,001 to $1,000,000		
$1,000,001 to $5,000,000		
$5,000,001 to $10,000,000		
> $10,000,000		

In addition, in the event of a payment default, unless otherwise precluded, the ISO will also disclose the amount and type of collateral, if any, held by the ISO to secure the defaulting Transmission Customer's obligations to the ISO.

2.7.6 Stranded Costs

The Transmission Owners other than NYPA may seek to recover stranded costs from the Transmission Customer pursuant to this Tariff in accordance with the terms, conditions and procedures set forth in Commission Order No. 888. However, the Transmission Owners must separately file any proposal to recover stranded costs under Section 205 of the FPA. This provision shall not supersede or otherwise affect a Transmission Owner’s right to recover stranded costs under other authority. To the extent that LIPA’s rates for service are established by LIPA’s Board of Trustees pursuant to Article 5, Title 1-A of the New York Public Authorities

Law, Sections 1020-f(u) and 1020-s and are not subject to Commission and/or PSC jurisdiction, LIPA's recovery of stranded costs will not be subject to the foregoing requirements.

Upon filing of a proposal to recover stranded costs under the FPA, the Transmission Owner shall immediately provide the ISO with a copy of the appropriate rate schedule which will be incorporated as a new Stranded Service and Point-to-Point Service Customers and remit the collected amounts to the applicable Transmission Owner(s). Any SIRC rate schedule developed by LIPA under this Tariff will be effective upon receipt by the ISO, subject to any applicable laws and orders.

6.1 Schedule 1 - ISO Annual Budget Charge and Other Non-Budget Charges and Payments

6.1.1 Introduction

The ISO shall bill each Transmission Customer each Billing Period to recover the ISO's annual budgeted costs as set forth in Section 6.1.2 of this Rate Schedule 1.

The ISO shall separately bill each Transmission Customer under this Rate Schedule 1 for certain other charges and payments not related to the ISO annual budget charge. Specifically, the ISO shall bill each Transmission Customer on a quarterly basis to recover NERC and NPCC charges and on a Billing Period basis to recover FERC charges as set forth in Sections 6.1.3 and 6.1.15 respectively of this Rate Schedule 1. The ISO shall also bill each Transmission Customer each Billing Period to recover the following costs or allocate the following received payments under this Rate Schedule 1:

(i) bad debt loss charges as set forth in Section 6.1.4;

(ii) Working Capital Fund charges as set forth in Section 6.1.5;

(iii) non-ISO facilities payment charges as set forth in Section 6.1.6;

(iv) charges to recover costs for payments made to Suppliers pursuant to incremental cost recovery for units that responded to Local Reliability Rules I-R3 and I-R5 as set forth in Section 6.1.7;

(v) charges to recover and payments to allocate residual costs as set forth in Section 6.1.8;

(vi) charges for Special Case Resources and Curtailment Service Providers called to meet reliability needs as set forth in Section 6.1.9;

(vii) charges to recover DAMAP costs as set forth in Section 6.1.10;

(viii) charges to recover Import Curtailment Guarantee Payment costs as set forth in Section 6.1.11;

(ix) charges to recover Bid Production Cost guarantee payment costs as set forth in Section 6.1.12;

(x) charges to recover and payments to allocate settlements of disputes as set forth in Section 6.1.13; and

(xi) payments to allocate financial penalties collected by the ISO as set forth in Section 6.1.14.

Transmission Customers who are retail access customers being served by an LSE shall not pay these charges to the ISO; the LSE shall pay these charges.

6.1.2 ISO Annual Budget Charge

The ISO shall charge, and each Transmission Customer shall pay, a charge for the ISO's recovery of its annual budgeted costs. The ISO annual budgeted costs that are recoverable through this Rate Schedule 1 are set forth in Section 6.1.2.1 of this Rate Schedule 1. The ISO shall calculate the charge for the recovery of these ISO annual budgeted costs from each Transmission Customer on the basis of its participation in physical market activity as indicated in Section 6.1.2.2 of this Rate Schedule 1. The ISO shall calculate this charge for each Transmission Customer on the basis of its participation in non-physical market activity, the Special Case Resource program, and the Emergency Demand Response program as indicated in Section 6.1.2.4 of this Rate Schedule 1. The ISO shall use the revenue collected through Section 6.1.2.4 of this Rate Schedule 1 to recover any of its annual budgeted costs for the immediately preceding calendar year that it has not already recovered under Section 6.1.2.2 of this Rate Schedule for that year. The ISO shall credit any additional revenue collected through Section

6.1.2.4 of this Rate Schedule 1 for the remainder of the calendar year to each Transmission Customer on the basis of its physical market activity as indicated in Section 6.1.2.5 of this Rate Schedule 1.

6.1.2.1 ISO Annual Budgeted Costs

The ISO annual budgeted costs to be recovered through Section 6.1.2 of this Rate Schedule 1 include, but are not limited to, the following costs associated with the operation of the NYS Transmission System by the ISO and the administration of the ISO Tariffs and ISO Related Agreements by the ISO:

- Processing and implementing requests for Transmission Service including support of the ISO OASIS node;
- Coordination of Transmission System operation and implementation of necessary control actions by the ISO and support for these functions;
- Performing centralized security constrained dispatch to optimally re-dispatch the NYS Power System to mitigate transmission Interface overloads and provide balancing services;
- Costs related to the ISO's administration and operation of the LBMP market and all other markets administered by the ISO;
- Costs related to the ISO's administration of Control Area Services;
- Costs related to the ISO's administration of the ISO's Market Power Mitigation Measures and the ISO's Market Monitoring Plan;
- Costs related to the maintenance of reliability in the NYCA;
- Costs related to the provision of Transmission Service;
- Preparation of settlement statements;
- NYS Transmission System studies, when the costs of the studies are not recoverable from a Transmission Customer;
- Engineering services and operations planning;
- Data and voice communications network service coordination;
- Metering maintenance and calibration scheduling;
- Record keeping and auditing;
- Training of ISO personnel;

- Development and maintenance of information, communication and control systems;
- Professional services;
- Carrying costs on ISO assets, capital requirements and debts;
- Tax expenses, if any;
- Administrative and general expenses;
- Insurance premiums and deductibles related to ISO operations;
- Any indemnification of or by the ISO pursuant to Section 2.11.2 of this ISO OATT or Section 12.4 of the Services Tariff;
- Regulatory fees; and
- The ISO's share of the expenses of Northeast Power Coordinating Council, Inc. or its successor.

6.1.2.2 Calculation of the ISO Annual Budget Charge for Transmission Customers Participating in Physical Market Activity

The ISO shall charge, and each Transmission Customer that participates in physical market activity shall pay, an ISO annual budget charge each Billing Period as calculated according to the following formula.

$$ISO\ Annual\ Budget\ Charge_{c,P}$$
$$= \left(InjectionUnits_{c,P} * \left(0.28 * \frac{ISOCosts_{Annual}}{TotalEstWithdrawalUnits_{Annual}} \right) \right)$$
$$+ \left(WithdrawalUnits_{c,P} * \left(0.72 * \frac{ISOCosts_{Annual}}{TotalEstWithdrawalUnits_{Annual}} \right) \right)$$

Where:

c = Transmission Customer.

P = The relevant Billing Period.

$ISO\ Annual\ Budget\ Charge_{c,P}$ = The amount, in $, of the ISO annual budgeted costs for which Transmission Customer c is responsible for Billing Period P.

$ISOCosts_{Annual}$ = The sum, in $, of the ISO's annual budgeted costs for the current calendar year.

$InjectionUnits_{c,P}$ = The Injection Billing Units, in MWh, for Transmission Customer c in Billing Period P, except for Scheduled Energy Injections at a CTS Enabled Interface with ISO New England resulting from Imports that are not associated with wheels through New England.

$WithdrawalUnits_{c,P}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer c in Billing Period P, except for Scheduled Energy Withdrawals at a CTS Enabled Interface with ISO New England resulting from Exports that are not associated with wheels through New England.

$TotalEstWithdrawalUnits_{Annual}$ = The sum, in MWh, of estimated Withdrawal Billing Units for all Transmission Customers in the current calendar year as determined by the ISO in the summer prior to the current calendar year, except for Scheduled Energy Withdrawals at a CTS Enabled Interface with ISO New England resulting from Exports that are not associated with wheels through New England.

6.1.2.3 Review and Modification of the ISO Annual Budget Charge Allocation Methodology

The current 72%/28% cost allocation methodology between Withdrawal Billing Units and Injection Billing Units for the ISO annual budget charge shall remain unchanged through at least December 31, 2016 and shall continue to remain unchanged until such point in time that a study is conducted and the results of the study warrant changing the 72%/28% cost allocation. The following provisions prescribe the process and timeline for the review and, if warranted by the results of a future study, modification of the 72%/28% cost allocation on a going forward basis:

(i) A vote of the Management Committee will be taken in the third calendar quarter of 2015 on whether a new study should be conducted during late-2015 and 2016 to allow modification of the 72%/28% cost allocation, if warranted by the results of the study, to be implemented by January 1, 2017. A positive vote by 58% of the Management Committee will be required to go forward with the study, but there will no longer be a “material change” standard as was historically applied to the determination of whether a study should be conducted.

(ii) If the Management Committee vote discussed in (i) above determines that a study should not be conducted, the 72%/28% cost allocation between Withdrawal Billing Units and Injection Billing Units shall be extended through at least December 31, 2017. In the third calendar quarter of 2016, a vote will be taken on whether a new study should be conducted during late-2016 and 2017 to allow modification of the percentage allocation, if warranted by the results of the study, to be implemented by January 1, 2018. Unless a 58% vote of the Management Committee is registered in favor of declining to go forward with the study, the study will be conducted.

(iii) If the Management Committee vote in the third calendar quarter of 2016 discussed in (ii) above determines that a study should not be conducted, the current 72%/28% cost allocation shall remain unchanged until such point in time as the Management Committee determines that a study shall be conducted and the results of that study warrant changing the percentage allocation between Withdrawal Billing Units and Injection Billing Units. If the Management Committee vote in the third calendar quarter of 2016 discussed in (ii) above determines that a study should not be conducted, the Management Committee will revisit the issue of conducting a study annually in the third calendar quarter of each year using the same voting standard (*i.e.* the study shall be performed unless 58% of the Management Committee votes not to commission the study) that was applied to the Management Committee vote in the third calendar quarter of 2016 discussed in (ii) above.

(iv) If, and when, the Management Committee determines a study shall be conducted:

(a) Such study shall be completed, and the results thereof shared with Market Participants, before the end of the second calendar quarter of the year prior to the date on which a possible change to the then current allocation may become effective; and

(b) The ISO will present a draft study scope to Market Participants for consideration and comment before the ISO issues the study scope as part of its Request For Proposal process to retain a consultant to perform the study. A meeting shall be held with Market Participants to discuss the components (*e.g.*, categories of costs considered, allocation of benefits, unbundling, etc.) that should be included in the draft study scope before the draft is issued by the ISO.

6.1.2.4 Calculation of the ISO Annual Budget Charge for Transmission Customers Participating in Non-Physical Market Activity, the Special Case Resource Program, or the Emergency Demand Response Program

6.1.2.4.1 Charge for Transmission Customers Engaging in Virtual Transactions

The ISO shall charge, and each Transmission Customer that has its virtual bids accepted and thereby engages in Virtual Transactions shall pay, a charge for such activity each Billing Period as calculated according to the following formula.

$$VTCharge_{c,P} = VTRate * VTCleared_{c,P}$$

Where:

c = Transmission Customer.

P = The relevant Billing Period.

$VTCharge_{c,P}$ = The amount, in $, for which Transmission Customer *c* is responsible for Billing Period *P*.

VTRate = For calendar year 2012, the applicable rate shall be $0.0871 per cleared MWh of Virtual Transactions, based on a $2.6 million projected 2012 annual revenue requirement. For calendar years following 2012, the applicable rate shall be calculated in accordance with the formula set forth in Section 6.1.2.4.4 of this Rate Schedule 1.

$VTCleared_{c,P}$ = The total cleared Virtual Transactions, in MWh, for Transmission Customer *c* in Billing Period *P*.

6.1.2.4.2 Charge for Transmission Customers Purchasing Transmission Congestion Contracts

The ISO shall charge, and each Transmission Customer that purchases Transmission Congestion Contracts - excluding Transmission Congestion Contracts that are created prior to January 1, 2010 - shall pay, a charge for such activity each Billing Period as calculated according to the following formula.

$$TCCCharge_{c,P} = TCCRate * TCCSettled_{c,P}$$

Where:

c = Transmission Customer.

P = The relevant Billing Period.

$TCCCharge_{c,P}$ = The amount, in $, for which Transmission Customer *c* is responsible for Billing Period *P*.

TCCRate = For calendar year 2012, the applicable rate shall be $0.0372 per settled MWh of Transmission Congestion Contracts, based on a $4.9 million projected 2012 annual revenue requirement. For calendar years following 2012, the applicable rate shall be calculated in accordance with the formula set forth in Section 6.1.2.4.4 of this Rate Schedule 1.

$TCCSettled_{c,P}$ = The total settled Transmission Congestion Contracts, excluding Transmission Congestion Contracts created prior to January 1, 2010, in MWh, for Transmission Customer *c* in Billing Period *P*.

6.1.2.4.3 Charge for Transmission Customers Participating in the Special Case Resource Program or Emergency Demand Response Program

The ISO shall charge, and each Transmission Customer that participates in the ISO's Special Case Resources program or its Emergency Demand Response program shall pay, a charge for such activity each Billing Period as calculated according to the following formula.

$$SCR\ and\ EDR\ Charge_{c,P} = DRInjections_{c,P} * \left(0.28 * \frac{ISOCosts_{Annual}}{TotalEstWithdrawalUnits_{Annual}}\right)$$

Where:

c = Transmission Customer.

P = The relevant Billing Period.

$SCR\ and\ EDR\ Charge_{c,P}$ = The amount, in $, for which Transmission Customer c is responsible for Billing Period P.

$DRInjections_{c,P}$ = The total Load reduction, in MWh, measured and compensated during testing or an actual event for Transmission Customer c in Billing Period P.

$ISOCosts_{Annual}$ = The sum, in $, of the ISO's annual budgeted costs in the current calendar year.

$TotalEstWithdrawalUnits_{Annual}$ = The sum, in MWh, of estimated Withdrawal Billing Units for all Transmission Customers in the current calendar year as determined by the ISO in the summer prior to the current calendar year, except for Scheduled Energy Withdrawals at a CTS Enabled Interface with ISO New England resulting from Exports that are not associated with wheels through New England.

6.1.2.4.4 Re-setting of Rate for Virtual Transaction and Transmission Congestion Contracts Related Charges

For each calendar year after calendar year 2012, the ISO shall use the following formula to calculate (i) the rate for the charge to Transmission Customers engaging in Virtual Transactions as determined in Section 6.1.2.4.1 of this Rate Schedule 1, and (ii) the rate for the charge to Transmission Customers purchasing Transmission Congestion Contracts as determined in Section 6.1.2.4.2 of this Rate Schedule 1.

$$ResetRate = \frac{AnnRevRequirement - Over/UnderCollection}{3YearRollingAvgBillUnits}$$

Where:

ResetRate = For each calendar year after calendar year 2012, this rate will be used for either (i) the VTRate in the formula in Section 6.1.2.4.1 of this Rate Schedule 1, or (ii) the TCCRate in the formula in Section 6.1.2.4.2 of this Rate Schedule 1.

AnnRevRequirement = The product, in $, of (i) the prior year's annual revenue requirement for either (A) Virtual Transaction market activity or (B) Transmission Congestion Contract market activity, and (ii) an escalation factor. The ISO shall calculate the escalation factor as the percentage change in the ISO budget between (i) the ISO budget for the calendar year two years prior to the current calendar year ("Calendar Year Minus 2") and (ii) the ISO budget for the calendar year one year prior to the current calendar year ("Calendar Year Minus 1").

Over/Under Collection = The ISO shall calculate the amount, in $, that it has over or under collected for the prior year's annual revenue requirement for either (A) Virtual Transaction market activity or (B) Transmission Congestion Contract market activity, as the case may be, as follows: (i) The ISO shall divide the annual revenue requirements for the applicable market activity for Calendar Year Minus 2 and for Calendar Year Minus 1 into twelve equal monthly revenue requirements for each of these calendar years. (ii) The ISO shall then calculate the amount of revenue, in $, that it over or under collected for each of the months from July of Calendar Year Minus 2 through June of Calendar Year Minus 1, which shall be calculated as (a) the revenue amount, in $, that the ISO collected for each month for the applicable market activity, minus (b) the monthly revenue requirement, in $, for that month as determined above. If the result of this calculation is positive, then the ISO overcollected for that month. If the result of this calculation is negative, then the ISO undercollected for that month. (iii) The ISO shall then calculate the total over or under collection amount, in $, for the period of July of Calendar Year Minus 2 through June of Calendar Year Minus 1, which shall be equal to (a) the sum, in $, of the revenue that the ISO overcollected for each month during this period (i.e., the sum of the positive monthly results determined above), minus (b) the sum, in $, of the absolute value of the revenue that the ISO undercollected for each month during this period (i.e., the sum of the absolute value of the negative monthly results determined above).

3YearRollingAvgBillUnits = The ISO shall calculate the three year rolling average of billing units, in MWh, using twelve-month averages of the appropriate billing units for the period between July of the calendar year four years prior to the current calendar year ("Calendar Year Minus 4") and June of Calendar Year Minus 1.

The annual rate computed through the formula in this Section 6.1.2.4.4 shall be subject to a 25% maximum increase or decrease for each year.

6.1.2.5 Credit for Transmission Customers Participating in Physical Market Activity After Recovery of ISO Annual Budgeted Costs or Actual Costs for the Preceding Year

The ISO shall use the revenue collected each Billing Period pursuant to Section 6.1.2.4 of this Rate Schedule 1 to recover the lower of: (i) its annual budgeted costs for the immediately preceding calendar year; or (ii) its actual costs for the immediately preceding calendar year, which it has not already recovered under Section 6.1.2 of this Rate Schedule for that year. Once it has recovered its annual budgeted costs or actual costs for the immediately preceding calendar year, the ISO shall distribute each Billing Period for the remainder of the calendar year any additional revenue collected pursuant to Section 6.1.2.4 of this Rate Schedule to each Transmission Customer that participates in physical market activity as calculated according to the following formula.

$$ISO\ Annual\ Budget\ Credit_{c,P} = \left(NonPhysicalActivityRevenue_P * \left(0.28 * \frac{InjectionUnits_{c,P}}{TotalInjectionUnits_P}\right)\right) + \left(NonPhysicalActivityRevenue_p * \left(0.72 * \frac{WithdrawalUnits_{c,P}}{TotalWithdrawalUnits_P}\right)\right)$$

Where:

c = Transmission Customer.

P = The relevant Billing Period.

$ISO\ Annual\ Budget\ Credit_{c,P}$ = The amount, in \$, that Transmission Customer *c* will receive for Billing Period *P*.

$NonPhysicalActivityRevenue_P$= The sum, in \$, of the revenue collected by the ISO for Billing Period *P* through the charges to Transmission Customers for non-physical market activity as calculated in Section 6.1.2.4 of this Rate Schedule 1, less the amount the ISO is using to recover the annual budgeted costs or actual costs for the immediately preceding calendar year that it did not recover 1) under Section 6.1.2.2 of this Rate Schedule for that year or 2) through NonPhysicalActivityRevenue previously used for this purpose in the current calendar year provided, however, $NonPhysicalActivityRevenue_P$ shall not be less than zero

$InjectionUnits_{c,P}$ = The Injection Billing Units, in MWh, for Transmission Customer c in Billing Period P, except for Scheduled Energy Injections at a CTS Enabled Interface with ISO New England resulting from Imports that are not associated with wheels through New England.

$WithdrawalUnits_{c,P}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer c in Billing Period P, except for Scheduled Energy Withdrawals at a CTS Enabled Interface with ISO New England resulting from Exports that are not associated with wheels through New England.

$TotalInjectionUnits_{P}$ = The sum, in MWh, of Injection Billing Units for all Transmission Customers in Billing Period P, except for Scheduled Energy Injections at a CTS Enabled Interface with ISO New England resulting from Imports that are not associated with wheels through New England.

$TotalWithdrawalUnits_{P}$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in Billing Period P, except for Scheduled Energy Withdrawals at a CTS Enabled Interface with ISO New England resulting from Exports that are not associated with wheels through New England

Following the end of calendar year 2017, the ISO shall review the credits that have been made to Transmission Customers participating in physical market activity pursuant to this Section 6.1.2.5 and shall present the results of its review to Market Participants for comment.

6.1.3 NERC and NPCC Charges

The ISO receives an invoice from NERC and NPCC (as defined below) on a quarterly basis for the recovery of the upcoming calendar quarter's costs related to the dues, fees, and related charges of:

(i) the NERC for its service as the Electric Reliability Organization for the United States ("ERO"), recovered pursuant to FERC Docket Nos. RM05-30-000, RR06-1-000 and RR06-3-000 and related dockets, and

(ii) the Northeast Power Coordinating Council: Cross-Border Regional Entity, Inc. ("NPCC"), or its successors, incurred to carry out functions that are delegated by the NERC and that are related to ERO matters pursuant to Section 215 of the FPA.

The ISO shall charge on a quarterly basis, and each Transmission Customer taking service under the ISO Tariffs shall pay, a charge for the recovery of the NERC and NPCC costs in accordance with Section 6.1.3.1 of this Rate Schedule 1.

Notwithstanding any applicable provisions of this ISO OATT or of the ISO Services Tariff, the ISO may supply to NERC the name of any LSE failing to pay any amounts due to NERC and the amounts not paid.

6.1.3.1 Calculation of NERC and NPCC Charges

The ISO shall charge, and each Transmission Customer shall pay, a charge on a quarterly basis to recover the NERC and NPCC costs invoiced to the NYISO by NERC and NPCC for the upcoming calendar quarter. This charge shall be calculated according to the following formula.

$$NERC\&NPCC\ Charge_{c,Q} = NERC\&NPCCCosts_Q * \frac{TUWithdrawalUnits_{c,M}}{TUTotalWithdrawalUnits_M}$$

Where:

c = Transmission Customer.

Q = The relevant calendar quarter, for which the NERC and NPCC costs apply.

$NERC\&NPCC\ Charge_{c,Q}$ = The amount of the NERC and NPCC costs invoiced to the ISO, in $, for which Transmission Customer c is responsible for calendar quarter Q.

$NERC\&NPCCCosts_Q$ = The NERC and NPCC costs, in $, invoiced to the ISO for calendar quarter Q.

M = The month in which the ISO charges Transmission Customers to recover NERC and NPCC costs for calendar quarter Q.

$TUWithdrawalUnits_{c,M}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer c in its four-month true-up invoice that is issued with its regular monthly invoice in month M, except for Withdrawal Billing Units for Wheels Through and Exports.

$TUTotalWithdrawalUnits_M$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in their four-month true-up invoices that are issued with their regular monthly invoices in month M, except for Withdrawal Billing Units for Wheels Through and Exports.

In calculating the Withdrawal Billing Units for this NERC and NPCC charge, the ISO shall use the LSE bus meter data that have been submitted by the meter authorities for use in the calculation of the four-month true-up of the Transmission Customer's monthly invoice pursuant to Sections 7.4.1.1.2 and 7.4.1.1.3 of the ISO Services Tariff and Sections 2.7.4.2.1(ii) and 2.7.4.2.1(iii) of this ISO OATT. This calculation of the NERC and NPCC charge shall not be subject to correction or adjustment.

6.1.4 Bad Debt Loss Charge

The ISO shall charge, and each Transmission Customer shall pay, a charge for the recovery of bad debt losses in accordance with the methodology established in Attachment U of this ISO OATT.

6.1.5 Working Capital Fund Charge

The ISO shall charge, and each Transmission Customer shall pay, a charge for the collection and maintenance of the Working Capital Fund in accordance with the methodology established in Attachment V of this ISO OATT.

6.1.6 Non-ISO Facilities Payment Charge

The ISO shall charge, and each Transmission Customer shall pay, a charge in accordance with Section 6.1.6.5 of this Rate Schedule 1 for the recovery of the costs of the ISO's monthly payments to the owners of facilities that are needed for the economic and reliable operation of the NYS Transmission System. At present, the ISO makes such payments to:

(i) Consolidated Edison Co. of New York, Inc. for the purchase, installation, operation, and maintenance of phase angle regulators at the Hopatcong-Ramapo Interconnection between the ISO and PJM Interconnection, LLC (the "Ramapo PARs Charge"), and

(ii) Rochester Gas & Electric Corporation for the installation of a 135 MVAR Capacitor Bank at Rochester Station 80 on the cross-state 345 kV system.

6.1.6.1 Calculation of the Ramapo PARs Charge

The Ramapo PARs Charge is the Consolidated Edison Co. of New York ("Con Edison") component of the *NonISOFacilitiesCosts* defined in Section 6.1.6.5 below. Con Edison shall calculate the Ramapo PARs Charge using the procedures described in the 1993 PARs Facilities Agreement that was accepted for filing by FERC in Docket No. ER93-640-000 on May 10, 1993 (the "1993 Agreement"), irrespective of the effectiveness of the 1993 Agreement. The costs Con Edison may include in the Ramapo PARs Charge are limited to the categories of costs that are eligible for recovery under the 1993 Agreement, and by the rules in this Section.

In order to permit the replacement of the Ramapo 3500 PAR that failed in June of 2016 without further delay, commencing on July 1, 2017 Transmission Customers will begin reimbursing Con Edison for up to 100% of the costs Con Edison incurred or incurs to purchase and install a replacement for the 3500 PAR, and up to 100% of the going-forward costs Con Edison incurs to operate and maintain the 3500 PAR.

With regard to the Ramapo PAR installed in and in service since 2013 ("Installed PAR"), Con Edison shall not submit a Ramapo PARs Charge that would cause Transmission Customers to pay more than 50% of the costs Con Edison submitted for inclusion in the *Non-ISO Facilities Payment Charge* for the Installed PAR prior to July 1, 2017. Subject to the foregoing restriction, in order to permit the continued operation of the Ramapo Installed PAR, commencing on July 1, 2017, Transmission Customers will reimburse Con Edison for up to 100% of Con Edison's going-forward cost of purchasing, installing, operating and maintaining the Installed PAR.

If PJM Interconnection, LLC ("PJM"), on behalf of some or all of its customers, assumes an obligation to pay a portion of the Ramapo PARs Charge, then the obligation of Transmission Customers to pay the Ramapo PARs Charge shall be reduced consistent with the obligation that PJM Interconnection, LLC assumes.

6.1.6.2 Transparency of the Ramapo PARs Charge

The ISO shall post on its web site the itemized monthly bill (for the preceding month) that Con Edison develops and submits to the ISO in accordance with Section 2.4 of the 1993 Agreement. The itemized monthly bill determines the Ramapo PARs Charge.

No later than August 1 of each year Con Edison shall prepare and the ISO shall post on is website an estimate of the monthly costs and expenses associated with the Ramapo PARs for the next calendar year and for each of the four subsequent years.

Con Edison shall maintain books and records related to its calculation of Ramapo PARs Charge, including costs incurred. Such books and records shall be subject to review by any New York Transmission Customer at reasonable intervals during normal business hours.

6.1.6.3 Refund of the Ramapo PARs Charge to Transmission Customers

To the extent Transmission Customers paid more than 50% of the Ramapo PARs Charge for a Billing Period, they shall be eligible to receive a refund if and to the extent Con Edison's cost recovery exceeds 100% of the Ramapo PARs Charge for that Billing Period.

If PJM, or one or more PJM transmission owners, submit(s) a payment to the ISO covering Ramapo PARs Charges assessed by Con Edison for a past period that is on or after July

1, 2017, and the conditions set forth in the first paragraph of this Section 6.1.6.3 are satisfied, then appropriate refunds shall be paid to Transmission Customers in accordance with the rules set forth below.

If PJM or any of the PJM transmission owners submit payments to Con Edison covering Ramapo PARs Charges assessed by Con Edison on or after July 1, 2017 and the conditions set forth in the first paragraph of this Section 6.1.6.3 are satisfied, then Con Edison shall refund to the ISO any amounts it received in excess of 100% of the Ramapo PARs Charge for a Billing Period and the ISO shall distribute the refund it receives from Con Edison in accordance with the rules set forth below.

If the ISO receives a refund from Con Edison, or a payment from PJM or from one or more PJM transmission owners related to the Ramapo PARs Charge, then the ISO shall refund the amount received to its Transmission Customers as soon as practicable. Refunds shall be allocated to each Transmission Customer based on its market participation in the Billing Period during which refunds are issued, using the same load ratio share basis that the ISO uses to allocate the *NonISOFacilitiesCosts* charges to Transmission Customers. Interest paid to the ISO shall be allocated to each Transmission Customer in the same manner as refunds are allocated.

6.1.6.4 Retirement and Replacement of the Ramapo PARs

If either of the Ramapo PARs described in Section 6.1.6.1 fail and are not reparable, or are retired with the consent of the ISO, then the original cost of the facilities retired shall be deducted from the gross plant in service and any unrecovered book cost shall be increased by the cost of removal and reduced by any salvage value, tax benefits, and insurance proceeds. The net balance shall be billed to the ISO for payment to Con Edison in a lump sum in accordance with the calculation, transparency, and cost allocation provisions applicable to the Ramapo PARs Charge.

If either of the Ramapo PARs described in Section 6.1.6.1 are damaged or condemned, the ISO may direct Con Edison to repair or replace them, provided that: (1) the costs of such repair or replacement net any insurance proceeds shall be recovered by Con Edison in accordance with the calculation, transparency, and cost allocation provisions applicable to the Ramapo PARs Charge; (2) Con Edison shall be the sole party responsible for determining whether a repair or replacement is in accordance with good utility practice; and (3) the schedule for any such repair or replacement shall be determined by Con Edison based on reliability considerations.

6.1.6.5 Calculation of Non-ISO Facilities Payment Charge

6.1.6.5.1 Transmission Customer Charge Based on Withdrawal Billing Units Not Used to Supply Station Power Under Section 5 of this ISO OATT

The ISO shall charge, and each Transmission Customer shall pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, a non-ISO facilities payment charge for each Billing Period. This charge shall be equal to the sum of the hourly non-ISO facilities payment charges for the Transmission Customer, as calculated according to the following formula, for each hour in the relevant Billing Period.

$$Non\text{-}ISO\ Facilities\ Payment\ Charge_{c,h} = \frac{NonISOFacilitiesCost_M}{N} * \frac{WithdrawalUnits_{c,h}}{TotalWithdrawalUnits_h}$$

Where:

c = Transmission Customer.

M = The relevant month.

h = A given hour in the relevant Billing Period in month M.

N = Total number of hours h in month M.

$Non\text{-}ISO\ Facilities\ Payment\ Charge_{c,h}$ = The amount, in \$, for which Transmission Customer *c* is responsible for hour *h*.

$NonISOFacilitiesCosts_M$ = The sum, in \$, of the ISO's bills for month M for the non-ISO facilities from (i) Consolidated Edison Co. of New York (less the portion, if any, of such bill paid by PJM Interconnection, LLC) and (ii) Rochester Gas and Electric Corporation.

$WithdrawalUnits_{c,h}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer *c* in hour *h*, except for the Withdrawal Billing Units to supply Station Power as a third-party provider and except for Scheduled Energy Withdrawals at a CTS Enabled Interface with ISO New England resulting from Exports that are not associated with wheels through New England.

$TotalWithdrawalUnits_h$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in hour *h*, except for the Withdrawal Billing Units to supply Station Power as third-party providers and except for Scheduled Energy Withdrawals at a CTS Enabled Interface with ISO New England resulting from Exports that are not associated with wheels through New England.

6.1.6.5.2 Transmission Customer Charge Based on Withdrawal Billing Units to Supply Station Power Under Section 5 of this ISO OATT.

The ISO shall charge, and each Transmission Customer shall pay based on its Withdrawal Billing Units used to supply Station Power as a third-party provider, a non-ISO facilities payment charge for each Billing Period. This charge shall be equal to the sum of the daily non-ISO facilities payment charges for the Transmission Customer, as calculated according to the following formula, for each day in the relevant Billing Period.

$$Non\text{-}ISO\ Facilities\ Payment\ Charge_{c,d} = \frac{NonISOFacilitiesCosts_M}{N} * \frac{StationPower_{c,d}}{TotalWithdrawalUnits_d}$$

Where:

d = A given day in the relevant Billing Period in month M.

N = Number of days d in month M.

$StationPower_{c,d}$ = The Withdrawal Billing Units, in MWh, of Transmission Customer *c* used to supply Station Power as a third-party provider for day *d*.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.6.5.1 of this Rate Schedule 1 above, except that the variables in this Section 6.1.6.5.2 shall be determined for day *d*.

6.1.6.5.3 Non-ISO Facilities Payment Credit

The ISO shall credit each Transmission Customer based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, an amount of the revenue collected through the non-ISO facilities payment charge under Section 6.1.6.5.2 of this Rate Schedule 1 for each Billing Period. This credit shall be equal to the sum of daily payments for the Transmission Customer, as calculated according to the following formula, for each day in the relevant Billing Period.

$$Non\text{-}ISO\ Facilities\ Payment\ Credit_{c,d} = NonISOFacPayCharge_d * \frac{WithdrawalUnits_{c,d}}{TotalWithdrawalUnits_d}$$

Where:

d = A given day in the relevant Billing Period.

$Non\text{-}ISO\ Facilities\ Payment\ Credit_{c,d}$ = The amount, in \$, that Transmission Customer *c* will receive for day *d*.

$NonISOFacPayCharge_d$ = The sum of non-ISO facilities payment charges, in \$, for all Transmission Customers as calculated in Section 6.1.6.5.2 of this Rate Schedule 1 for day *d*.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.6.5.1 of this Rate Schedule 1 above, except that the variables in this Section 6.1.6.5.3 shall be determined for day *d*.

6.1.7 Charge to Recover Payments Made to Suppliers Pursuant to Incremental Cost Recovery for Units Responding to Local Reliability Rules I-R3 and I-R5

The ISO shall charge, and each Transmission Customer shall pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, a charge for the recovery of the costs of payments to Suppliers pursuant to the incremental cost recovery for units that responded to either (i) Local Reliability Rule I-R3 or (ii) Local Reliability Rule I-R5, as applicable, for each Billing Period. This charge shall be equal to the sum of the daily charges for the Transmission Customer, as calculated according to the following formula, for each day in the relevant Billing Period. The ISO shall perform this calculation separately to recover as applicable either (i) the payment costs related to Local Reliability I-R3, or (ii) the payment costs related to Local Reliability Rule I-R5.

$$Local\ Reliability\ Rules\ Payment\ Recovery\ Charge_{c,d} = LRRPayment_d * \frac{TDWithdrawal_{c,d}}{TDTotalWithdrawalUnits_d}$$

Where:

c = Transmission Customer.

d = A given day in the relevant Billing Period.

$Local\ Reliability\ Rules\ Payment\ Recovery\ Charge_{c,d}$ = The amount, in \$, for which Transmission Customer *c* is responsible for day *d*.

$LRRPayment_d$ - The amount, in \$, paid in day *d* to Suppliers pursuant to the incremental cost recovery for units that responded, as applicable, to either (i) Local Reliability Rule I-R3 in the Consolidated Edison Transmission District or (ii) Local Reliability Rule I-R5 in the LIPA Transmission District.

$TDWithdrawalUnits_{c,d}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer *c* in day *d* in either (i) the Consolidated Edison Transmission District (in the case of Local Reliability Rule I-R3) or (ii) the LIPA Transmission District (in the case of Local Reliability Rule I-R5), except for the Withdrawal Billing Units to supply Station Power as a third-party provider.

$TDTotalWithdrawalUnits_d$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in day *d* in either (i) the Consolidated Edison Transmission District (in the case of Local Reliability Rule I-R3) or (ii) the LIPA Transmission District (in the case of Local Reliability Rule I-R5), except for the Withdrawal Billing Units to supply Station Power as third-party providers.

6.1.8 Residual Costs Payment/Charge

The ISO's payments for market transactions by Transmission Customers will not equal the ISO's payments to Suppliers for market transactions. Part of the difference consists of Day-Ahead Congestion Rent. The remainder comprises a residual adjustment, which the ISO shall calculate and each Transmission Customer shall receive or pay on the basis of its Withdrawal Billing Units. The most significant component of the residual adjustment is the residual costs payment or charge calculated in accordance with Section 6.1.8.1 of this Rate Schedule 1.

6.1.8.1 Calculation of Residual Costs Payment/Charge

6.1.8.1.1 Transmission Customers Charge Based on Withdrawal Billing Units Not Used to Supply Station Power Under Section 5 of this ISO OATT

The ISO shall calculate, and each Transmission Customer shall receive or pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, a residual costs payment or a residual costs charge for each Billing Period. The payment or charge for the relevant Billing Period shall be equal to (i) the sum of the hourly residual costs payments for the Transmission Customer as calculated according to the following formula for each hour in the relevant Billing Period, minus (ii) the sum of the hourly residual costs charges for the Transmission Customer as calculated in the following formula for each hour in the relevant Billing Period. If the result of this determination is positive, the ISO shall pay the Transmission Customer a residual costs payment for the relevant Billing Period. If the result of this determination is negative, the ISO shall charge the Transmission Customer a residual costs charge for the relevant Billing Period.

$$Residual\ Costs\ Payment/Charge_{c,h} = (CustomerPayments_h - ISOPayments_h) * \frac{WithdrawalUnits_{c,h}}{TotalWithdrawalUnits_h}$$

Where:

c = Transmission Customer.

h = A given hour in the relevant Billing Period.

$Residual\ Costs\ Payment/Charge_{c,h}$ = The amount, in \$, for hour h that Transmission Customer c will receive (if positive) or for which Transmission Customer c is responsible (if negative).

$WithdrawalUnits_{c,h}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer c in hour h, except for the Withdrawal Billing Units to supply Station Power as a third-party provider and except for Scheduled Energy Withdrawals at a CTS Enabled Interface with ISO New England resulting from Exports that are not associated with wheels through New England.

$TotalWithdrawalUnits_h$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in hour h, except for the Withdrawal Billing Units to supply Station Power as third-party providers and except for Scheduled Energy Withdrawals at a CTS Enabled Interface with ISO New England resulting from Exports that are not associated with wheels through New England.

$CustomerPayments_h$ = The ISO's receipts, in \$, for each hour h from Transmission Customers that equal the sum of the following components, which could be either positive or negative amounts:

(i) payments of the Energy component and Marginal Losses Component of LBMP for Energy scheduled in the LBMP Market in hour h in the Day-Ahead Market;

(ii) payments of the Energy component, Marginal Losses Component, and Congestion Component of LBMP for Energy purchased in the Real-Time LBMP Market for hour h that was not scheduled Day-Ahead;

(iii) payments of the Energy component, Marginal Losses Component, and Congestion Component of LBMP for Energy by Suppliers that provided less Energy in the real-time dispatch for hour h than they were scheduled Day-Ahead to provide in hour h for the LBMP Market;

(iv) the Marginal Losses Component of the TUC payments made in accordance with this ISO OATT for Bilateral Transactions that were scheduled in hour h in the Day-Ahead Market; and

(v) the Marginal Losses Component and Congestion Component of the real-time TUC payments made in accordance with this ISO OATT for Bilateral Transactions that were not scheduled in hour h in the Day-Ahead Market.

(vi) the M2M settlement between the ISO and PJM Interconnection, L.L.C. for hour h, determined in accordance with Section 8 of Schedule D to Attachment CC to this ISO OATT.

$ISOPayments_h$ = The ISO's payments, in $, in each hour h to Suppliers that equal the sum of the following components, which could be either positive or negative amounts:

(i) payments of the Energy component and Marginal Losses Components of LBMP for Energy to Suppliers that were scheduled to provide in the LBMP Market in hour h in the Day-Ahead Market;

(ii) payments to Suppliers of the Energy component, Marginal Losses Component, and Congestion Component of LBMP for Energy, not including for Demand Reductions, provided to the ISO in the Real-Time Dispatch for hour h that those Suppliers were not scheduled to provide Energy in hour h in the Day-Ahead Market;

(iii) payments of the Energy component and Marginal Losses Component of LBMP for Energy to LSEs that consumed less Energy in the real-time dispatch than those LSEs were scheduled Day-Ahead to consume in hour h; and

(iv) payments of the Marginal Losses Component and Congestion Component of the real-time TUC to Transmission Customers that reduced their Bilateral Transaction schedules for hour h after the Day-Ahead Market.

6.1.8.1.2 Transmission Customer Charge Based on Withdrawal Billing Units to Supply Station Power Under Section 5 of this ISO OATT.

The ISO shall calculate, and each Transmission Customer shall receive or pay based on its Withdrawal Billing Units used to supply Station Power as a third-party provider, a residual costs payment or a residual costs charge for each Billing Period. The payment or charge for the relevant Billing Period shall be equal to (i) the sum of the daily residual costs payments for the Transmission Customer as calculated according to the following formula for each day in the relevant Billing Period, minus (ii) the sum of the daily residual costs charges for the Transmission Customer as calculated in the following formula for each day in the relevant Billing Period. If the result of this determination is positive, the ISO shall pay the Transmission Customer a residual costs payment for the relevant Billing Period. If the result of this determination is negative, the ISO shall charge the Transmission Customer a residual costs charge for the relevant Billing Period.

$$Residual\ Costs\ Payment/Charge_{c,d} = \frac{(CustomerPayments_d - ISOPayments_d)}{TotalWithdrawalUnits_d} * StationPower_{c,d}$$

Where:

d = A given day in the relevant Billing Period.

$StationPower_{c,d}$ = The Withdrawal Billing Units, in MWh, of Transmission Customer c that it used to supply Station Power as a third-party provider for day d.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.8.1.1 of this Rate Schedule 1 above, except that the variables in this Section 6.1.8.1.2 shall be determined for day d.

6.1.8.1.3 Residual Costs Adjustment

The ISO shall calculate, and each Transmission Customer shall receive or pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, a residual costs adjustment for each Billing Period. This adjustment shall be equal to the sum of the daily adjustments (positive and negative) for the Transmission Customer, as calculated according to the following formula, for each day in the relevant Billing Period. If the summed amount is positive for the Billing Period, the ISO shall pay the Transmission Customer the adjustment amount. If the summed amount is negative for the Billing Period, the ISO shall charge the Transmission Customer the adjustment amount.

$$Residual\ Costs\ Adjustment_{c,d} = ResidCharge/PaymentCosts_{d} * \frac{WithdrawalUnits_{c,d}}{TotalWithdrawalUnits_{d}}$$

Where:

d = A given day in the relevant Billing Period.

$Residual\ Costs\ Adjustment_{c,d}$ = The amount, in $, for day *d* that Transmission Customer *c* will receive (if positive) or for which Transmission Customer *c* is responsible (if negative).

$ResidCharge/PaymentCosts_{d}$ = (i) If Transmission Customers were responsible for a residual costs charge for day *d* pursuant to Section 6.1.8.1.2 of this Rate Schedule 1, the (positive) amount, in $, of the costs that the ISO has collected through the residual costs charges for all Transmission Customers for day *d*. (ii) If Transmission Customers received a residual costs payment for day *d* pursuant to Section 6.1.8.1.2 of this Rate Schedule 1, the (negative) amount, in $, of the revenue that the ISO has paid through the residual costs payments to all Transmission Customers for day *d*.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.8.1.1 of this Rate Schedule 1 above, except that the variables in this Section 6.1.8.1.3 shall be determined for day *d*.

6.1.9 Recovery of Special Case Resources and Curtailment Services Providers Costs

The ISO shall charge, and each Transmission Customer shall pay, a charge for the recovery of Special Case Resources and Curtailment Service Providers costs for each Billing Period. This charge shall be equal to the sum of the hourly charges for the Transmission Customer, as calculated in Sections 6.1.9.1 and 6.1.9.2 of this Rate Schedule 1, for each hour in the relevant Billing Period and, where applicable, for each Subzone.

6.1.9.1 Recovery of Costs for Payments for Special Case Resources and Curtailment Service Providers Called to Meet the Reliability Needs of a Local System

Pursuant to this Section 6.1.9.1, the ISO shall recover the costs of payments to Special Case Resources and Curtailment Service Providers that were called to meet the reliability needs of a local system. To do so, the ISO shall charge, and each Transmission Customer that serves Load in the Subzone for which the reliability services of the Special Case Resources and Curtailment Service Providers were called shall pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, an hourly charge in accordance with the following formula for each Subzone.

$$Local\ Reliability\ SCR\ and\ CSP\ Charge_{c,h} = LocalReliabilityCosts_h * \frac{SZWithdrawalUnits_{c,h}}{SZTotalWithdrawalUnits_h}$$

Where:

c = Transmission Customer.

h = A given hour in the relevant Billing Period.

$Local\ Reliability\ SCR\ and\ CSP\ Charge_{c,h}$ = The amount, in $, for which Transmission Customer c is responsible for hour h for the relevant Subzone.

$LocalReliabilityCosts_h$ = The payments, in $, for hour h in the relevant Subzone made to Suppliers for Special Case Resources and Curtailment Service Providers called to meet the reliability needs of that Subzone.

$SZWithdrawalUnits_{c,h}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer *c* in hour *h* in the relevant Subzone, except for Withdrawal Billing Units for Wheels Through, Exports, and to supply Station Power as a third-party provider.

$SZTotalWithdrawalUnits_{h}$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in hour *h* in the relevant Subzone, except for Withdrawal Billing Units for Wheels Through, Exports, and to supply Station Power as third-party providers.

6.1.9.2 Recovery of Costs for Payments for Special Case Resources and Curtailment Service Providers Called to Meet the Reliability Needs of the NYCA

Pursuant to this Section 6.1.9.2, the ISO shall recover the costs of payments to Special Case Resources and Curtailment Service Providers called to meet the reliability needs of the NYCA. To do so, the ISO shall charge, and each Transmission Customer shall pay based on its Withdrawal Billing Units except for Withdrawal Billing Units for Wheels Through, Exports or to supply Station Power as a third-party provider, an hourly charge in accordance with the following formula.

$$NYCA\ Reliability\ SCR\ and\ CSP\ Charge_{c,h} = NYCAReliabilityCosts_{h} * \frac{WithdrawalUnits_{c,h}}{TotalWithdrawalUnits_{h}}$$

Where:

c = Transmission Customer.

h = A given hour in the relevant Billing Period.

$NYCA\ Reliability\ SCR\ and\ CSP\ Charge_{c,h}$ = The amount, in \$, for which Transmission Customer *c* is responsible for hour *h*.

$NYCAReliabilityCosts_{h}$ = The payments, in \$, for hour *h* made to Suppliers for Special Case Resources and Curtailment Service Providers called to meet the reliability needs of the NYCA.

$WithdrawalUnits_{c,h}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer *c* in hour *h*, except for the Withdrawal Billing Units for Wheels Through, Exports or to supply Station Power as a third-party provider.

$TotalWithdrawalUnits_h$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in hour *h*, except for the Withdrawal Billing Units for Wheels Through, Exports or to supply Station Power as third-party providers.

6.1.10. Recovery of Day-Ahead Margin Assurance Payment Costs

The ISO shall charge, and each Transmission Customer shall pay, a charge for the recovery of DAMAP costs for each Billing Period. The charge for the relevant Billing Period shall be equal to the sum of the charges and credits for the Transmission Customer, as calculated in Sections 6.1.10.1 and 6.1.10.2 of this Rate Schedule 1, for each hour or each day, as applicable, in the relevant Billing Period and for each Subzone, where applicable.

6.1.10.1 Recovery of Costs of DAMAPs Resulting from Meeting the Reliability Needs of a Local System

Pursuant to this Section 6.1.10.1, the ISO shall recover the costs for DAMAPs incurred to compensate Resources for meeting the reliability needs of a local system.

6.1.10.1.1 Transmission Customer Charge Based on Withdrawal Billing Units Not Used to Supply Station Power Under Section 5 of this ISO OATT

The ISO shall charge, and each Transmission Customer that serves Load in the Subzone where the Resource is located shall pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, an hourly charge in accordance with the following formula for each Subzone.

$$Local\ Reliability\ DAMAP\ Charge_{c,h} = DAMAPCosts_h * \frac{SZWithdrawalUnits_{c,h}}{SZTotalWithdrawalUnits_h}$$

Where:

c = Transmission Customer.

h = A given hour in the relevant Billing Period.

$Local\ Reliability\ DAMAP\ Charge_{c,h}$ = The amount, in $, for which Transmission Customer c is responsible for hour *h* for the relevant Subzone.

$DAMAPCosts_h$ = The DAMAP costs, in $, for hour *h* in the relevant Subzone incurred to compensate Resources meeting the reliability needs of that Subzone.

$SZWithdrawalUnits_{c,h}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer *c* in hour *h* in the relevant Subzone, except for Withdrawal Billing Units for Wheels Through, Exports, and to supply Station Power as a third-party provider.

$SZTotalWithdrawalUnits_h$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in hour *h* in the relevant Subzone, except for Withdrawal Billing Units for Wheels Through, Exports, and to supply Station Power as third-party providers.

6.1.10.1.2 Transmission Customer Charge Based on Withdrawal Billing Units to Supply Station Power Under Section 5 of this ISO OATT

The ISO shall charge, and each Transmission Customer that serves Load in the Subzone where the Resource is located shall pay based on its Withdrawal Billing Units used to supply Station Power as a third-party provider, a daily charge in accordance with the following formula for each Subzone.

$$Local\ Reliability\ DAMAP\ Charge_{c,d} = \frac{DAMAPCosts_d}{SZTotalWithdrawalUnits_d} * \ SZStationPower_{c,d}$$

Where:

d = A given day in the relevant Billing Period.

$SZStationPower_{c,d}$ = The Withdrawal Billing Units, in MWh, of Transmission Customer *c* in day *d* in the relevant Subzone that are used to supply Station Power as a third-party provider, except for Withdrawal Billing Units for Wheels Through and Exports.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.10.1.1 of this Rate Schedule 1 above, except that the variables in this Section 6.1.10.1.2 shall be determined for day *d*.

6.1.10.1.3 Local Reliability DAMAP Credit

The ISO shall calculate, and each Transmission Customer that serves Load in the Subzone where the Resource is located shall receive based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, an amount of the revenue collected through the charge under Section 6.1.10.1.2 of this Rate Schedule 1. This credit shall be calculated according to the following formula for each day in the relevant Billing Period.

$$Local\ Reliability\ DAMAP\ Credit_{c,d} = LocRelDAMAPCharge_{d} * \frac{SZWithdrawalUnits_{c,d}}{SZTotalWithdrawalUnits_{d}}$$

Where:

d = A given day in the relevant Billing Period.

$Local\ Reliability\ DAMAP\ Credit_{c,d}$ = The amount, in $, that Transmission Customer c will receive for day d for the relevant Subzone.

$LocRelDAMAPCharge_{d}$ = The sum of charges, in $, for all Transmission Customers in the relevant Subzone as calculated in Section 6.1.10.1.2 of this Rate Schedule 1 for day d.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.10.1.1 of this Rate Schedule 1 above, except that the variables in this Section 6.1.10.1.3 shall be determined for day d.

6.1.10.2 Recovery of Costs of All Remaining DAMAPs

Pursuant to this Section 6.1.10.2, the ISO shall recover the costs of all DAMAPs not recovered through Section 6.1.10.1 of this Rate Schedule 1 from all Transmission Customers.

6.1.10.2.1 Transmission Customer Charge Based on Withdrawal Billing Units Not Used to Supply Station Power Under Section 5 of this ISO OATT

The ISO shall charge, and each Transmission Customer shall pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, an hourly charge in accordance with the following formula.

$$Remaining\ DAMAP\ Charge_{c,h} = RemainingDAMAPCosts_{h} * \frac{WithdrawalUnits_{c,h}}{TotalWithdrawalUnits_{h}}$$

Where:

c = Transmission Customer.

h = A given hour in the relevant Billing Period.

$Remaining\ DAMAP\ Charge_{c,h}$ = The amount, in \$, for which Transmission Customer c is responsible for hour h.

$RemainingDAMAPCosts_h$ = The DAMAP costs, in \$, for hour h not recovered by the ISO through Section 6.1.10.1 of this Rate Schedule 1.

$WithdrawalUnits_{c,h}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer c in hour h, except for the Withdrawal Billing Units to supply Station Power as a third-party provider and except for Scheduled Energy Withdrawals at a CTS Enabled Interface with ISO New England resulting from Exports that are not associated with wheels through New England.

$TotalWithdrawalUnits_h$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in hour h, except for the Withdrawal Billing Units to supply Station Power as third-party providers and except for Scheduled Energy Withdrawals at a CTS Enabled Interface with ISO New England resulting from Exports that are not associated with wheels through New England.

6.1.10.2.2 Transmission Customer Charge Based on Withdrawal Billing Units to Supply Station Power Under Section 5 of this ISO OATT

The ISO shall charge, and each Transmission Customer shall pay based on its Withdrawal Billing Units used to supply Station Power as a third-party provider, a daily charge in accordance with the following formula.

$$Remaining\ DAMAP\ Charge_{c,d} = \frac{RemainingDAMAPCosts_d}{TotalWithdrawalUnits_d} * StationPower_{c,d}$$

Where:

d = A given day in the relevant Billing Period.

$StationPower_{c,d}$ = The Withdrawal Billing Units, in MWh, of Transmission Customer c used to supply Station Power as a third-party provider for day d.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.10.2.1 of this Rate Schedule 1 above, except that the variables in this Section 6.1.10.2.2 shall be determined for day d.

6.1.10.2.3 Remaining DAMAP Credit

The ISO shall calculate, and each Transmission Customer shall receive based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, an amount of the revenue collected through the charge under Section 6.1.10.2.2 of this Rate Schedule 1. This credit shall be calculated according to the following formula for each day in the relevant Billing Period.

$$Remaining\ DAMAP\ Credit_{c,d} = RemainingDAMAPCharge_{d} * \frac{WithdrawalUnits_{c,d}}{TotalWithdrawalUnits_{c,d}}$$

Where:

d = A given day in the relevant Billing Period.

$Remaining\ DAMAP\ Credit_{c,d}$ = The amount, in \$, that Transmission Customer c will receive for day d.

$RemainingDAMAPCharge_{d}$ = The sum of charges, in \$, for all Transmission Customers as calculated in Section 6.1.10.2.2 of this Rate Schedule 1 for day d.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.10.2.1 of this Rate Schedule 1 above, except that the variables in this Section 6.1.10.2.3 shall be determined for day d.

6.1.11 Recovery of Import Curtailment Guarantee Payment Costs

6.1.11.1 Transmission Customer Charge Based on Withdrawal Billing Units Not Used to Supply Station Power Under Section 5 of this ISO OATT

The ISO shall charge, and each Transmission Customer shall pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, a charge each Billing Period to recover the costs of all Import Curtailment Guarantee Payments paid to Import Suppliers for that Billing Period. The charge for the relevant Billing Period shall be equal to the sum of the hourly charges for the Transmission Customer, as calculated in accordance with the following formula, for each hour in the relevant Billing Period.

$$Import\ Curtailment\ Guarantee\ Charge_{c,h} = ImportCurtGuarCosts_h * \frac{WithdrawalUnits_{c,h}}{TotalWithdrawalUnits_h}$$

Where:

c = Transmission Customer.

h = A given hour in the relevant Billing Period.

$Import\ Curtailment\ Guarantee\ Charge_{c,h}$= The amount, in $, for which Transmission Customer *c* is responsible for hour *h*.

$ImportCurtGuarCosts_h$ = The costs, in $, for the Import Curtailment Guarantee Payments to Import Suppliers for hour *h*.

$WithdrawalUnits_{c,h}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer *c* in hour *h*, except for the Withdrawal Billing Units to supply Station Power as a third-party provider and except for Scheduled Energy Withdrawals at a CTS Enabled Interface with ISO New England resulting from Exports that are not associated with wheels through New England.

$TotalWithdrawalUnits_h$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in hour *h*, except for the Withdrawal Billing Units to supply Station Power as third-party providers and except for Scheduled Energy Withdrawals at a CTS Enabled Interface with ISO New England resulting from Exports that are not associated with wheels through New England.

6.1.11.2 Transmission Customer Charge Based on Withdrawal Billing Units to Supply Station Power Under Section 5 of this ISO OATT

The ISO shall charge, and each Transmission Customer shall pay based on its Withdrawal Billing Units used to supply Station Power as a third-party provider, a charge for each Billing Period to recover the costs of all Import Curtailment Guarantee Payments paid to Import Suppliers for that Billing Period. The charge for the relevant Billing Period shall be equal to the sum of the daily charges for the Transmission Customer, as calculated in accordance with the following formula, for each day in the relevant Billing Period.

$$Import\ Curtailment\ Guarantee\ Charge_{c,d} = \frac{ImportCurtGuarCosts_d}{TotalWithdrawalUnits_d} * StationPower_{c,d}$$

Where:

d = A given day in the relevant Billing Period.

$StationPower_{c,d}$ = The Withdrawal Billing Units, in MWh, of Transmission Customer c used to supply Station Power as a third-party provider for day d.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.11.1 of this Rate Schedule 1 above, except that the variables in this Section 6.1.11.2 shall be determined for day d.

6.1.11.3 Import Curtailment Guarantee Credit

The ISO shall credit each Transmission Customer based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, an amount of the revenue collected through the charge under Section 6.1.11.2 of this Rate Schedule 1 above for each Billing Period. This credit shall be equal to the sum of daily payments for the Transmission Customer, as calculated according to the following formula, for each day in the relevant Billing Period.

$$Import\ Curtailment\ Guarantee\ Credit_{c,d} = ImpCurtGuarCharge_d * \frac{WithdrawalUnits_{c,d}}{TotalWithdrawalUnits_d}$$

Where:

d = A given day in the relevant Billing Period.

$Import\ Curtailment\ Guarantee\ Credit_{c,d}$ = The amount, in \$, that Transmission Customer c will receive for day d.

$ImpCurtGuarCharge_d$ = The sum of charges, in \$, for all Transmission Customers as calculated in Section 6.1.11.2 of this Rate Schedule 1 for day d.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.11.1 of this Rate Schedule 1 above, except that the variables in this Section 6.1.11.3 shall be determined for day d.

6.1.12 Recovery of Bid Production Cost Guarantee Payment Costs

6.1.12.1 Costs of BPCGs for Additional Generating Units Committed to Meet Forecast Load

If the sum of all Bilateral Transaction schedules, excluding schedules of Bilateral Transactions with Trading Hubs as their POWs, and all Day-Ahead Market purchases to serve Load in the Day-Ahead schedule is less than the ISO's Day-Ahead forecast of Load, the ISO may commit Resources in addition to the reserves that it normally maintains to enable it to respond to contingencies to meet the ISO's Day-Ahead forecast of Load. The ISO shall recover a portion of the costs associated with Bid Production Cost guarantee payments for the additional Resources committed Day-Ahead to meet the Day-Ahead forecast of Load from Transmission Customers pursuant to the methodology established in Attachment T of this ISO OATT. The ISO shall recover the residual costs of such Bid Production Cost guarantee payments not recovered through the methodology in Attachment T of the ISO OATT pursuant to Section 6.1.12.5 of this Rate Schedule 1.

6.1.12.2 Costs of BPCGs Resulting from Meeting the Reliability Needs of a Local System

Pursuant to this Section 6.1.12.2, the ISO shall recover the costs for Bid Production Cost guarantee payments incurred to compensate Suppliers for their Resources, other than Special Case Resources, that are committed or dispatched to meet the reliability needs of a local system.

6.1.12.2.1 Transmission Customer Charge Based on Withdrawal Billing Units Not Used to Supply Station Power Under Section 5 of this ISO OATT

The ISO shall charge, and each Transmission Customer that serves Load in the Subzone where the Resource is located shall pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, a daily charge in accordance with the following formula for each Subzone.

$$Local\ Reliability\ BPCG\ Charge_{c,d} = BPCGCosts_d * \frac{SZWithdrawalUnits_{c,d}}{SZTotalWithdrawalUnits_d}$$

Where:

c = Transmission Customer.

d = A given day in the relevant Billing Period.

$Local\ Reliability\ BPCG\ Charge_{c,d}$ = The amount, in $, for which Transmission Customer *c* is responsible for day *d* for the relevant Subzone.

$BPCGCosts_d$ = The Bid Production Cost guarantee payments, in $, made to Suppliers for Resources for day *d* in the relevant Subzone arising as a result of meeting the reliability needs of that Subzone, except for the Bid Production Cost guarantee payments made to Suppliers for Special Case Resources.

$SZWithdrawalUnits_{c,d}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer *c* in day *d* in the relevant Subzone, except for Withdrawal Billing Units for Wheels Through, Exports, and to supply Station Power as a third-party provider.

$SZTotalWithdrawalUnits_d$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in day *d* in the relevant Subzone, except for Withdrawal Billing Units for Wheels Through, Exports, and to supply Station Power as third-party providers.

6.1.12.2.2 Transmission Customer Charge Based on Withdrawal Billing Units to Supply Station Power Under Section 5 of this ISO OATT

The ISO shall charge, and each Transmission Customer that serves Load in the Subzone where the Resource is located shall pay based on its Withdrawal Billing Units used to supply Station Power as a third-party provider, a daily charge in accordance with the following formula for each Subzone.

$$Local\ Reliability\ BPCG\ Charge_{c,d} = \frac{BPCGCosts_d}{SZTotalWithdrawalUnits_d} * SZStationPower_{c,d}$$

Where:

$SZStationPower_{c,d}$ = The Withdrawal Billing Units, in MWh, of Transmission Customer *c* in day *d* in the relevant Subzone that are used to supply Station Power as a third-party provider, except for Withdrawal Billing Units for Wheels Through and Exports.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.12.3.1 above,

6.1.12.2.3 Local Reliability BPCG Credit

The ISO shall calculate, and each Transmission Customer that serves Load in the Subzone where the Resource is located shall receive based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, an amount of the revenue collected through the charge under Section 6.1.12.2.2 of this Rate Schedule 1. This credit shall be calculated according to the following formula for each day in the relevant Billing Period.

$$Local\ Reliability\ BPCG\ Credit_{c,d} = LocRelBPCGCharge_d * \frac{SZWithdrawalUnits_{c,d}}{SZWithdrawalUnits_{c,d}}$$

Where:

$Local\ Reliability\ BPCG\ Credit_{c,d}$ = The amount, in $, that Transmission Customer *c* will receive for day *d* for the relevant Subzone.

$LocRelBPCGCharge_d$ = The sum of charges, in $, for all Transmission Customers in the relevant Subzone as calculated in Section 6.1.12.2.2 of this Rate Schedule 1 for day *d*.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.12.2.1 above.

6.1.12.3 Cost of BPCGs for Special Case Resources Called to Meet the Reliability Needs of a Local System

Pursuant to this Section 6.1.12.3, the ISO shall recover the costs of Bid Production Cost guarantee payments incurred to compensate Special Case Resources called to meet the reliability needs of a local system. To do so, the ISO shall charge, and each Transmission Customer that serves Load in the Subzone where the Special Case Resource is located shall pay based on its

Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, a daily charge in accordance with the following formula for each Subzone.

$$Local\ Reliability\ SCR\ BPCG\ Charge_{c,d} = BPCGCosts_d * \frac{SZWithdrawalUnits_{c,d}}{SZTotalWithdrawalUnits_d}$$

Where:

c = Transmission Customer.

d = A given day in the relevant Billing Period.

$Local\ Reliability\ SCR\ BPCG\ Charge_{c,d}$ = The amount, in \$, for which Transmission Customer c is responsible for day d for the relevant Subzone.

$BPCGCosts_d$ = The Bid Production Cost guarantee payments, in \$, made to Suppliers for Special Case Resources for day *d* in the relevant Subzone arising as a result of meeting the reliability needs of that Subzone.

$SZWithdrawalUnits_{c,d}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer *c* in day *d* in the relevant Subzone, except for Withdrawal Billing Units for Wheels Through, Exports, and to supply Station Power as a third-party provider.

$SZTotalWithdrawalUnits_d$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in day *d* in the relevant Subzone, except for Withdrawal Billing Units for Wheels Through, Exports, and to supply Station Power as third-party providers.

6.1.12.4 Cost of BPCG for Special Case Resources Called to Meet the Reliability Needs of the NYCA

Pursuant to this Section 6.1.12.4, the ISO shall recover the costs for Bid Production Cost guarantee payments to compensate Special Case Resources called to meet the reliability needs of the NYCA. To do so, the ISO shall charge, and each Transmission Customer shall pay based on its Withdrawal Billing Units used except for Withdrawal Billing Units for Wheels Through, Exports or to supply Station Power as a third-party provider, a daily charge in accordance with the following formula.

$$NYCA\ Reliability\ SCR\ BPCG_{c,d} = BPCGCost_d * \frac{WithdrawalUnits_{c,d}}{TotalWithdrawalUnits_d}$$

Where:

c = Transmission Customer.

d = A given day in the relevant Billing Period.

$NYCA\ Reliability\ SCR\ BPCG\ Charge_{c,d}$ = The amount, in \$, for which Transmission Customer c is responsible for day d.

$BPCGCosts_d$ = The Bid Production Cost guarantee payments, in \$, made to Suppliers for Special Case Resources called to meet the reliability needs of the NYCA for day d.

$WithdrawalUnits_{c,d}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer c in day d, except for the Withdrawal Billing Units for Wheels Through, Exports or to supply Station Power as a third-party provider.

$TotalWithdrawalUnits_d$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in day d, except for the Withdrawal Billing Units for Wheels-Through, Exports or to supply Station Power as third-party providers.

6.1.12.5 Costs of All Remaining BPCGs

Pursuant to this Section 6.1.12.5, the ISO shall recover the costs of all Bid Production Cost guarantee payments not recovered through Sections 6.1.12.1, 6.1.12.2, 6.1.12.3, and 6.1.12.4 of this Rate Schedule 1, including the residual costs of Bid Production Cost guarantee payments for additional Resources not recovered through the methodology in Attachment T of this ISO OATT, from all Transmission Customers.

6.1.12.5.1 Transmission Customer Charge Based on Withdrawal Billing Units Not Used to Supply Station Power Under Section 5 of this ISO OATT

The ISO shall charge, and each Transmission Customer shall pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, a daily charge in accordance with the following formula.

$$Remaining\ BPCG\ Charge_{c,d} = RemainingBPCGCosts_d * \frac{WithdrawalUnits_{c,d}}{TotalWithdrawalUnits_d}$$

Where:

c = Transmission Customer.

d = A given day in the relevant Billing Period.

$Remaining\ BPCG\ Charge_{c,d}$ = The amount, in $, for which Transmission Customer *c* is responsible for day *d*.

$RemainingBPCGCosts_d$ = The BPCG costs, in $, for day *d* not recovered by the ISO through Sections 6.1.12.1, 6.1.12.2, 6.1.12.3, and 6.1.12.4 of this Rate Schedule 1.

$WithdrawalUnits_{c,d}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer *c* in day *d*, except for the Withdrawal Billing Units to supply Station Power as a third-party provider and except for Scheduled Energy Withdrawals at a CTS Enabled Interface with ISO New England resulting from Exports that are not associated with wheels through New England.

$TotalWithdrawalUnits_d$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in day *d*, except for the Withdrawal Billing Units to supply Station Power as third-party providers and except for Scheduled Energy Withdrawals at a CTS Enabled Interface with ISO New England resulting from Exports that are not associated with wheels through New England.

6.1.12.5.2 Transmission Customer Charge Based on Withdrawal Billing Units to Supply Station Power Under Section 5 of this ISO OATT

The ISO shall charge, and each Transmission Customer shall pay based on its Withdrawal Billing Units used to supply Station Power as a third-party provider, a daily charge in accordance with the following formula.

$$Remaining\ BPCG\ Charge_{c,d} = \frac{RemainingBPCGCosts_d}{TotalWithdrawalUnits_d} * \ StationPower_{c,d}$$

Where:

$StationPower_{c,d}$ = The Withdrawal Billing Units, in MWh, of Transmission Customer *c* used to supply Station Power as a third-party provider for day *d*.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.12.5.1 of this Rate Schedule 1 above.

6.1.12.5.3 Remaining BPCG Credit

The ISO shall calculate, and each Transmission Customer shall receive based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, an amount of the revenue collected through the charge under Section 6.1.12.5.2 of this Rate Schedule 1. This credit shall be calculated according to the following formula for each day in the relevant Billing Period.

$$Remaining\ BPCG\ Credit_{c,d} = RemainingBPCGCharge_d * \frac{WithdrawalUnits_{c,d}}{TotalWithdrawalUnits_{c,d}}$$

Where:

$Remaining\ BPCG\ Credit_{c,d}$ = The amount, in $, that Transmission Customer *c* will receive for day *d*.

$RemainingBPCGCharge_d$ = The sum of charges, in $, for all Transmission Customers as calculated in Section 6.1.12.5.2 of this Rate Schedule 1 for day *d*.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.12.5.1 of this Rate Schedule 1 above.

6.1.13 Dispute Resolution Payment/Charge

The ISO shall calculate, and each Transmission Customer shall receive or pay, a dispute resolution payment or charge in accordance with Section 6.1.13.1 of this Rate Schedule 1 for the distribution of funds received by the ISO or the recovery of funds incurred by the ISO in the settlement of a dispute.

6.1.13.1 Calculation of the Dispute Resolution Payment/Charge

The ISO shall calculate, and each Transmission Customer shall receive or pay, a dispute resolution payment or a dispute resolution charge for each Billing Period as calculated according to the following formula.

$$Dispute\ Resolution\ Payment/Charge_{c,P} = DisputeResolutionCosts_P * \frac{WithdrawalUnits_{c,P}}{TotalWithdrawalUnits_P}$$

Where:

c = Transmission Customer.

P = The relevant Billing Period.

$Dispute\ Resolution\ Payment/Charge_{c,P}$ = The amount, in $, for Billing Period *P* that (i) Transmission Customer *c* will receive if the ISO is distributing funds that it has collected in the settlement of a dispute, or (ii) Transmission Customer *c* will be responsible for if the ISO is recovering funds that it has incurred in the settlement of a dispute.

$DisputeResolutionCosts_P$ = The amount, in $, for Billing Period *P* that (i) the ISO has collected in the settlement of a dispute or (ii) the ISO has incurred in the settlement of a dispute.

$WithdrawalUnits_{c,P}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer *c* in Billing Period *P*, except for Scheduled Energy Withdrawals at a CTS Enabled Interface with ISO New England resulting from Exports that are not associated with wheels through New England.

$TotalWithdrawalUnits_P$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in Billing Period *P*, except for Scheduled Energy Withdrawals at a CTS Enabled Interface with ISO New England resulting from Exports that are not associated with wheels through New England.

6.1.14 Credit for Financial Penalties

The ISO shall distribute to each Transmission Customer each Billing Period in accordance with the following formula any payments that it has collected from Transmission Customers to satisfy: (i) Financial Impact Charges issued pursuant to Sections 4.5.3.2 and 4.5.4.2 of the ISO Services Tariff; (ii) ICAP sanctions issued pursuant to Section 5.12.12 of the ISO Services Tariff; (iii) ICAP deficiency charges pursuant to Section 5.14.3.1 of the ISO Services Tariff, except as provided in Section 5.14.3.2 of the ISO Services Tariff; (iv) market power mitigation financial penalties pursuant to Section 23.4.3.6 of Attachment H of the ISO Services Tariff, except as provided in Section 23.4.4.3.2 of Attachment H of the ISO Services Tariff; and (v) any other financial penalties set forth in the ISO Services Tariff or this ISO OATT. The ISO will perform this calculation separately for the allocation of the revenue from each financial penalty.

$$Financial\ Penalties\ Credit_{c,P} = PenaltyRevenue_P * \frac{WithdrawalUnits_{c,P}}{TotalWithdrawalUnits_P}$$

Where:

c = Transmission Customer.

P = A given day in the relevant Billing Period.

$Financial\ Penalties\ Credit_{c,P}$ = The amount, in $, that Transmission Customer c will receive for Billing Period P.

$PenaltyRevenue_P$ = The sum, in $, of revenue that the ISO has collected for Billing Period P from a Transmission Customer for one of the financial penalties indicated in Section 6.1.14 of this Rate Schedule 1.

$WithdrawalUnits_{c,P}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer c for Billing Period P, except for Scheduled Energy Withdrawals at a CTS Enabled Interface with ISO New England resulting from Exports that are not associated with wheels through New England.

$TotalWithdrawalUnits_P$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers for Billing Period P, except for Scheduled Energy Withdrawals at a CTS Enabled Interface with ISO New England resulting from Exports that are not associated with wheels through New England.

6.1.15 Calculation of FERC Fee Charges

As a public utility the transmission provider under this Tariff is subject to annual charges assessed by the Commission in accordance with Part 382 of the Commission's regulations (annual FERC fee). The ISO shall charge, and each Transmission Customer taking service under the ISO Tariffs shall pay, a charge for the recovery of the annual FERC fee, on the basis of its participation in physical market activity, and on the basis of its participation in non-physical market activity in accordance with Sections 6.1.15.1 and 6.1.15.2 respectively. The annual FERC fee shall be allocated ninety-four (94%) to physical market activity and six (6%) to non-physical market activity respectively. Pursuant to ISO Procedures, the six (6%) of the annual FERC fee allocated to non-physical market activity shall be further allocated approximately four percent (4%) to Transmission Congestion Contracts and approximately two percent (2%) to Virtual Transactions. The total charge to each Transmission Customer for recovery of the annual FERC fee shall be the sum of the Transmission Customer's Physical FERC Fee Charge and the Transmission Customer's Non-Physical FERC Fee Charge.

An estimated annual FERC fee shall be recovered over the twelve months of each federal fiscal year. The ISO will publish the estimated annual FERC fee for each federal fiscal year no less than one month in advance of the start of that federal fiscal year. Upon receiving the invoice for the annual FERC fee, the ISO will implement a true-up, a credit or charge, equal to the difference between the estimated annual FERC fee for the fiscal year and the invoiced amount, in the first Billing Period following receipt of the invoiced annual FERC fee, as is practicable. The ISO shall recover or refund the true-up amount over a six month period.

All funds collected by the ISO for the annual FERC fee shall be deposited in the annual FERC fee account. The annual FERC fee account shall be an interest-bearing account separate from all other accounts maintained by the ISO. The ISO shall disburse funds from the annual FERC fee account in order to pay the FERC any and all annual FERC fee charges assessed against the ISO.

6.1.15.1 Calculation of Physical FERC Fee Charge for Transmission Customers Participating in Physical Market Activity

The ISO shall charge, and each Transmission Customer that participates in physical market activity shall pay, a charge for the recovery of the annual FERC fee as calculated according to the following formula:

$$Physical\ FERC\ Fee\ Charge_{c,P}$$
$$= \left(Injection\ Units_{c,P} * \left(0.28 * PRatio * \frac{(Est\ FERC\ Fee_P + True\text{-}Up\ Costs_P)}{TotalInjectionUnits_P}\right)\right)$$
$$+ \left(Withdrawal\ Units_{c,P} * \left(0.72 * \ PRatio * \frac{(Est\ FERC\ Fee_P + True\text{-}Up\ Costs_P)}{TotalWithdrawalUnits_P}\right)\right)$$

Where:

c = Transmission Customer.

P = The relevant Billing Period.

$Physical\ FERC\ Fee\ Charge_{c,P}$ = The amount, in \$, of the annual FERC fee for which Transmission Customer c is responsible for Billing Period P.

$Injection\ Units_{c,P}$ = The Injection Billing Units, in MWh, for Transmission Customer c in Billing Period P.

$PRatio$ = Ninety-four percent (94%).

$Est\ FERC\ Fee_P$ = Billing Period P's proportional allocation of the estimated annual FERC fee for the current FERC fiscal year.

$True\text{-}up\ Costs_P$ = Billing Period P's proportional allocation of the difference between the invoiced annual FERC fee and the estimated annual FERC fee.

$TotalInjectionUnits_P$ = The sum, in MWh, of Injection Billing Units for all Transmission Customers in Billing Period P.

$Withdrawal\ Units_{c,P}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer c in the Billing Period P.

$TotalWithdrawalUnits_P$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in the Billing Period P.

6.1.15.2 Calculation of the FERC Fee Charge for Transmission Customers Participating in Non-Physical Market Activity

The ISO shall charge, and each Transmission Customer that has its virtual bids accepted and thereby engages in Virtual Transactions or that purchases Transmission Congestion Contracts shall pay, a charge for the recovery of the annual FERC fee as calculated according to the following formula: $Non\text{-}Physical\ FERC\ Fee\ Charge_{c,P} = \left(VTCleared_{c,P} * \left(\left(\frac{VTRatio * Est\ FERC\ Fee_P}{Total\ VT\ Cleared_P}\right) + \left(\frac{VTRatio * True\text{-}Up\ Costs_P}{Total\ VT\ Cleared_P}\right)\right)\right) + \left(TCC\ Settled_{c,P} * \left(\left(\frac{TCCRatio * Est\ FERC\ Fee_P}{Total\ TCC\ \ Settled_P}\right) + \left(\frac{TCCRatio * True\text{-}Up\ Costs_P}{Total\ TCC\ Settled_P}\right)\right)\right)$

Where:

c = Transmission Customer.

P = The relevant Billing Period.

$Non - Physical\ FERC\ Fee\ Charge_{c,P}$ = The amount, in $, of the annual FERC fee for which Transmission Customer c is responsible for Billing Period P.

$VT\ Cleared_{c,P}$ = The total cleared Virtual Transactions, in MWh, for Transmission Customer c in Billing Period P.

$Est\ FERC\ Fee_P$ = Billing Period P's proportional allocation of the estimated annual FERC fee for the current FERC fiscal year.

$True - up\ Costs_P$ = Billing Period P's proportional allocation of the difference between the invoiced annual FERC fee and the estimated annual FERC fee.

$VTRatio$ = Approximately two percent (2%).

$Total\ VT\ Cleared_P$ = The sum, in MWh, of cleared Virtual Transactions for all Transmission Customers in Billing Period P.

$TCCSettled_{c,P}$ = The total settled Transmission Congestion Contracts, in MWh, for Transmission Customer c in Billing Period P.

$TCCRatio$ = Approximately four percent (4%).

$Total\ TCC\ Settled_P$ = The sum of settled Transmission Congestion Contracts, in MWh, for all Transmission Customers in Billing Period P.

6.3 Schedule 3 - Charges for Regulation Service

Regulation Service is necessary to provide for the continuous balance of resources (generation and interchange) with Load. The obligation to maintain this balance between Resources and Load lies with the ISO. The ISO must offer this service when the Transmission Service is used to serve Load within the NYCA and when LSEs use Energy from the LBMP Market to service Load within the NYCA. The charges for Regulation Service are set forth below.

6.3.1 Customer Obligations and Responsibilities

LSEs shall purchase this service from the ISO.

6.3.2 Charges to LSEs

6.3.2.1 For all Actual Energy Withdrawals for Load located in the NYCA, LSE taking service under the OATT or buying Energy from the LBMP Market shall pay a charge for this service on all withdrawals to serve Load in the NYCA in accordance with this Rate Schedule.

6.3.2.2 The ISO shall charge LSEs serving Load in the NYCA for Regulation Service for each hour. The ISO shall charge LSEs taking service under Section 5 of the ISO OATT to supply Station Power as third-party providers for Service for each day. The charge shall be calculated as the Regulation Service Rate, determined as an hourly or a daily rate as appropriate, multiplied by the LSE's Load for the hour or by the LSE's withdrawals to provide Station Power as a third party provider for the day. The ISO shall calculate the Regulation Service Rate, for an hour or for a day as appropriate, as follows:

$$Rate_{Reg} = \frac{(Supplier\ Payment - Supplier\ Charge - Generator\ Charge)}{Load_{NYCA}}$$

where: $Rate_{Reg}$ is the hourly or daily rate for Regulation Service ($/MWh);

Supplier Payment is the aggregate of all Day-Ahead Market and Real-Time Market payments (including Regulation Revenue Adjustment Payments) made by the ISO to all Suppliers of this Regulation Service as described in Rate Schedule 3 of the ISO Services Tariff for the hour or for the day;

Supplier Charge is the aggregate of: (i) charges paid by all Suppliers for poor Regulation Service performance, as described in Section 15.3.5.4; (ii) all real-time imbalance charges paid by Suppliers under Section 15.3.5.2(a) of that Rate Schedule; and (iii) all Regulation Revenue Adjustment Charges assessed pursuant to Section 15.3.6 of that Rate Schedule for the hour or for the day;

Generator Charge is the aggregate of charges paid by all Generators and Aggregations that do not provide Regulation Service and do not follow their RTD Base Points sufficiently accurately, as described in Rate Schedule 3A of the ISO Services Tariff for the hour or for the day; and

$Load_{NYCA}$ is the total Load in the NYCA for the hour or for the day, as appropriate.

6.3.2.3 In any hour where the charges paid by Generators and Suppliers, as described in the ISO Services Tariff, exceed the payments made to Suppliers of this service (i) the ISO shall not assess a charge against any LSE, and (ii) the surplus will be applied to the following hour as an offset to subsequent payments.

6.3.2.4 Charges to be paid by LSEs for this service shall be aggregated to render a monthly charge. The ISO shall credit charges paid for Regulation Service by LSEs taking service under Section 5 of the ISO OATT to supply Station Power as third-party providers for the day on a Load ratio share basis to LSEs serving Load in the NYCA for the day.

6.4 Schedule 4 - Energy Imbalance Service

Energy Imbalance Service is provided Day-Ahead when a difference occurs between: (1) scheduled Transmission Service and scheduled delivery of Energy to a Load located within the NYCA from a POI located within the NYCA over a single hour, (2) scheduled Transmission Service and scheduled delivery of Energy to a Load located within the NYCA from a POI located external to the NYCA over the scheduling interval, and (3) scheduled Transmission Service and scheduled delivery of Energy from a POI within the NYCA to a neighboring control area over the scheduling interval.

Energy Imbalance Service is provided in real-time when a difference occurs between: (1) scheduled Transmission Service and scheduled delivery of Energy to a Load located within the NYCA from a POI located within the NYCA over the scheduling interval, (2) scheduled Transmission Service and scheduled delivery of Energy to a Load located within the NYCA from a POI located external to the NYCA over the scheduling interval, and (3) scheduled Transmission Service and scheduled delivery of Energy from a POI within the NYCA to a neighboring control area in the scheduling interval.

Differences between scheduled Transmission Service in the Day-Ahead Market and scheduled Transmission Service in the Real-Time Market for the same transaction are governed by Attachment J of the OATT, not by this Rate Schedule 4. Differences between the scheduled delivery of Energy in the Day-Ahead Market and the scheduled delivery of Energy in the Real-Time Market for the same transaction are governed by Section 4.5 of the Services Tariff, not by this Rate Schedule 4.

The ISO must offer this service when the Transmission Service is used to serve Load within the NYCA, or for an Export Transaction when the generation source is a Generator or

Aggregation located in the NYCA. The Transmission Customer, or Generator or Aggregations as appropriate, must purchase this service from the ISO. The charges for Energy Imbalance Service are set forth below.

6.4.1 Energy Imbalance Service Charges

Each Transmission Customer that has executed a Service Agreement under the ISO Services Tariff, whose scheduled Energy delivery in the Day-Ahead Market is less than its scheduled Transmission Service in the Day-Ahead Market, will be charged an amount equal to the product of the Day-Ahead LBMP determined pursuant to Attachment B of the Services Tariff, at the Point of Delivery (Point of Injection) and the difference between the scheduled Energy delivery in the Day-Ahead Market and the scheduled Transmission Service in the Day-Ahead Market, provided however, when the Energy delivery scheduled in the Day-Ahead Market is from a POI within the NYCA, Energy Imbalance Service is charged to the Generator or Aggregation associated with the POI.

Each Transmission Customer that has not executed a Service Agreement under the ISO Services Tariff, whose scheduled Energy delivery in the Day-Ahead Market is less than its scheduled Transmission Service in the Day-Ahead Market, will be charged an amount equal to the product of: (i) the higher of: (a) 150 percent of the Day-Ahead LBMP determined pursuant to Attachment B of the Services Tariff, at the Point of Delivery (Point of Injection); and (b) $100 per MWh, and (ii) the difference between the scheduled Energy delivery in the Day-Ahead Market and the scheduled Transmission Service in the Day-Ahead Market, provided however, when the scheduled delivery of Energy is from a POI within the NYCA, Energy Imbalance Service is charged to the Generator or Aggregation associated with the POI.

Each Transmission Customer that has executed a Service Agreement under the ISO Services Tariff whose scheduled Energy delivery in the Real-Time Market is less than its scheduled Transmission Service in the Real-Time Market, will be charged an amount equal to the product of the Real-Time LBMP price determined pursuant to Attachment B of the Services Tariff, at the Point of Delivery (Point of Injection) and the difference between the scheduled Energy delivery in the Real-Time Market and the scheduled Transmission Service in the Real-Time Market, provided however, when the scheduled delivery of Energy is from a POI within the NYCA, Energy Imbalance Service is charged to the Generator or Aggregation associated with the POI.

Each Transmission Customer that has not executed a Service Agreement under the ISO Services Tariff, whose scheduled Energy delivery in the Real-Time Market is less than its Transmission Service scheduled in the Real-Time Market, will be charged an amount equal to the product of (i) the higher of (a) 150 percent of the real-time LBMP determined pursuant to Attachment J, at the Point of Delivery (Point of Injection), and (b)$100 per MWh, and (ii) the difference between the scheduled Energy delivery in the Real-Time Market and the scheduled transmission service in the Real-Time Market, provided however, when the scheduled delivery of Energy is from a POI within the NYCA, Energy Imbalance Service is charged to the Generator or Aggregation associated with the POI.

Settlements when Actual Energy delivery exceeds Actual Energy Withdrawals are governed by Services Tariff Section 4.5.

Energy imbalances resulting from inadvertent interchange between Control Areas will continue to be addressed by ISO procedures and in accordance with NERC and NPCC policies. Any increase or decrease in costs resulting from pay back of accumulated inadvertent interchange will be included in the residual costs payment or the residual costs charge as calculated in Section 6.1.8 of Rate Schedule 1 of this ISO OATT.

6.4.2 Inadvertent Energy Management Requirements

6.4.2.1 Facilities on Boundaries with Neighboring Control Areas

The correction required for external Inadvertent Energy Accounting facilities on Interfaces between the NYCA and other Control Areas will be done using Inadvertent Energy Accounting techniques established by the ISO in accordance with NERC and other established reliability criteria.

6.4.3 Self-Supply

All Energy Imbalance Services shall be purchased from the ISO.

24 Attachment R - Cost Allocation and Measurement and Verification Methodologies for Demand Reductions by Distributed Energy Resources in a DER Aggregation

24.1 Cost Allocation Methodology for Demand Reductions Recovered Pursuant to Schedule 1

The "Schedule 1 Program Costs" for verified Actual Demand Reductions by DER Aggregations participating in the Energy and Ancillary Services Markets shall be equal to the Supplier payments for Demand Reductions calculated in accordance with ISO Services Tariff Section 4.5.2.

The "Schedule 1 Program Costs" for verified Demand Reductions by DER Aggregations participating in the Energy and Ancillary Services Markets shall be allocated to Transmission Customers, pursuant to the methodology set forth below, on the basis of their Load Ratio Shares and in proportion to the probability, given historical transmission congestion patterns, that a particular Demand Reduction will benefit them by reducing Energy costs in their Load Zones or "Composite Load Zones" (see below).

More specifically, Schedule 1 Program Costs shall be allocated to Transmission Customers each Billing Period as follows:

a) Schedule 1 Program Costs shall initially be attributed to the Load Zone where the Transmission Node used to Bid the associated Demand Reduction is located.

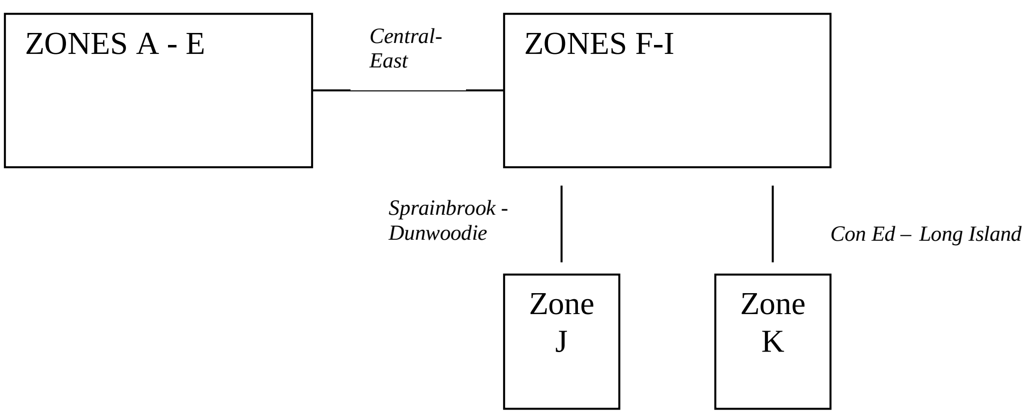
b) In determining whether and how Transmission Customers located in particular Load Zones, or Composite Load Zones, have benefited from the Energy provided by Demand Reduction, and how much they shall be required to pay a share of the associated Schedule 1 Program Costs, the ISO shall account for the effects of congestion at the most frequently constrained NYCA interfaces. When none of these interfaces are constrained Transmission Customers in all Load Zones shall be deemed to have benefited from the Energy provided by Demand Reduction and shall pay a share of the associated Schedule 1 Program Costs. When one or more of the most frequently constrained NYCA interfaces is constrained, then Transmission Customers located in a Load Zone, or Composite Load Zone, that is upstream of the constrained interface, shall be deemed to have benefited from the upstream Energy provided by Demand Reduction and shall be required to pay a share of the associated Schedule 1 Program Costs. Similarly, when one or more of the interfaces is congested, Transmission Customers located in a Load Zone, or Composite Load Zone, that is downstream of a constrained interface, shall be deemed to have benefited from the downstream Energy Provided by Demand Reduction and shall be required to pay a share of the associated Schedule 1 Program Costs. By contrast, Transmission Customers that are "separated" from the Energy provided by Demand Reduction by a constrained interface shall be deemed not to have benefited from it and shall not be required to pay a share of the associated Schedule 1 Program Costs.

c) The ISO shall determine the extent of congestion at the most frequently constrained interfaces using a series of equations that calculate the static probability that: (i) no constraints existed in the transmission system serving the Load Zone or Composite Load Zone; (ii) the Composite Load Zone was upstream of a constraint and Energy provided by Demand Reduction occurred upstream, and (iii) the Composite Load Zone was downstream of a constraint and Energy provided by Demand Reduction occurred downstream.

Costs shall be allocated to each Transmission Customer that is deemed to have benefited from the verified Demand Reduction on a Load Ratio Share basis, using Real-Time metered hourly Load data.

d) The three interfaces that will be used for this cost allocation are the "Central-East" interface, which divides western from eastern New York State, the Sprainbrook-Dunwoodie interface, which divides New York City and Long Island from the rest of New York State, and the Consolidated Edison Company ("ConEd") - Long Island interface (including the Y49/Y50 lines), which divides New York City from Long Island Given these limiting interfaces, four Composite Load Zones currently exist, *i.e.*, West of Central-East (Load Zones A, B, C, D, E,), East Upstate Excluding New York City and Long Island (Load Zones F, G, H, I), New York City (Load Zone J), and Long Island (Load Zone K). The geographic configuration of these Composite Load Zones is depicted in the illustration below.

Relationship Between Frequently Constrained Interfaces and Composite Load Zones



Based on these factors, Schedule 1 Program Costs shall be allocated to Transmission Customers as follows:

For Transmission Customer m in Load Zones A-E:

$a_1 * (\text{cost}_A+\ldots+\text{cost}_K) * \text{load}_m / (\text{load}_A+\ldots+\text{load}_K) +$ ‘no constraints
$a_2 * (\text{cost}_A+\ldots+\text{cost}_E) * \text{load}_m / (\text{load}_A+\ldots+\text{load}_E) +$ ‘Central East const
$a_3 * (\text{cost}_A+\ldots+\text{cost}_I+\text{cost}_K) * \text{load}_m / (\text{load}_A+\ldots+\text{load}_I+\text{load}_K) +$ ‘NYC constraint
$a_4 * (\text{cost}_A+\ldots+\text{cost}_J) * \text{load}_m / (\text{load}_A+\ldots+\text{load}_J) +$ ‘LI constraint
$a_5 * (\text{cost}_A+\ldots+\text{cost}_E) * \text{load}_m / (\text{load}_A+\ldots+\text{load}_E) +$ ‘Cent East + NYC
$a_6 * (\text{cost}_A+\ldots+\text{cost}_E) * \text{load}_m / (\text{load}_A+\ldots+\text{load}_E) +$ ‘Cent East + LI
$a_7 * (\text{cost}_A+\ldots+\text{cost}_I) * \text{load}_m / (\text{load}_A+\ldots+\text{load}_I) +$ ‘NYC + LI
$a_8 * (\text{cost}_A+\ldots+\text{cost}_E) * \text{load}_m / (\text{load}_A+\ldots+\text{load}_E)$ ‘Cent East + NYC + LI

For Transmission Customer m in Load Zones F-I:

$a_1 * (\text{cost}_A+\ldots+\text{cost}_K) * \text{load}_m / (\text{load}_A+\ldots+\text{load}_K) +$ ‘no constraints
$a_2 * (\text{cost}_F+\ldots+\text{cost}_K) * \text{load}_m / (\text{load}_F+\ldots+\text{load}_K) +$ ‘Central East const
$a_3 * (\text{cost}_A+\ldots+\text{cost}_I+\text{cost}_K) * \text{load}_m / (\text{load}_A+\ldots+\text{load}_I+\text{load}_K) +$ ‘NYC constraint
$a_4 * (\text{cost}_A+\ldots+\text{cost}_J) * \text{load}_m / (\text{load}_A+\ldots+\text{load}_J) +$ ‘LI constraint
$a_5 * (\text{cost}_F+\ldots+\text{cost}_I+\text{cost}_K) * \text{load}_m / (\text{load}_F+\ldots+\text{load}_I+\text{load}_K) +$ ‘Cent East + NYC
$a_6 * (\text{cost}_F+\ldots+\text{cost}_J) * \text{load}_m / (\text{load}_F+\ldots+\text{load}_J) +$ ‘Cent East + LI
$a_7 * (\text{cost}_A+\ldots+\text{cost}_I) * \text{load}_m / (\text{load}_A+\ldots+\text{load}_I) +$ ‘NYC + LI
$a_8 * (\text{cost}_F+\ldots+\text{cost}_I) * \text{load}_m / (\text{load}_F+\ldots+\text{load}_I)$ ‘Cent East + NYC + LI

For Transmission Customer m in Load Zone J:

$a_1 * (\text{cost}_A+\ldots+\text{cost}_K) * \text{load}_m / (\text{load}_A+\ldots+\text{load}_K) +$ ‘no constraints
$a_2 * (\text{cost}_F+\ldots+\text{cost}_K) * \text{load}_m / (\text{load}_F+\ldots+\text{load}_K) +$ ‘Central East const
$a_3 * \text{cost}_J * \text{load}_m / \text{load}_J +$ ‘NYC constraint
$a_4 * (\text{cost}_A+\ldots+\text{cost}_J) * \text{load}_m / (\text{load}_A+\ldots+\text{load}_J) +$ ‘LI constraint
$a_5 * \text{cost}_J * \text{load}_m / \text{load}_J +$ ‘Cent East + NYC
$a_6 * (\text{cost}_F+\ldots+\text{cost}_J) * \text{load}_m / (\text{load}_F+\ldots+\text{load}_J) +$ ‘Cent East + LI
$a_7 * \text{cost}_J * \text{load}_m / \text{load}_J +$ ‘NYC + LI
$a_8 * \text{cost}_J * \text{load}_m / \text{load}_J$ ‘Cent East + NYC + LI

For Transmission Customer m in Load Zone K:

$a_1 * (\text{cost}_A+\ldots+\text{cost}_K) * \text{load}_m / (\text{load}_A+\ldots+\text{load}_K) +$ ‘no constraints
$a_2 * (\text{cost}_F+\ldots+\text{cost}_K) * \text{load}_m / (\text{load}_F+\ldots+\text{load}_K) +$ ‘Central East const
$a_3 * (\text{cost}_A+\ldots+\text{cost}_I+\text{cost}_K) * \text{load}_m / (\text{load}_A+\ldots+\text{load}_I+\text{load}_K) +$ ‘NYC constraint
$a_4 * \text{cost}_K * \text{load}_m / \text{load}_K +$ ‘LI constraint
$a_5 * (\text{cost}_F+\ldots+\text{cost}_I+\text{cost}_K) * \text{load}_m / (\text{load}_F+\ldots+\text{load}_I+\text{load}_K) +$ ‘Cent East + NYC
$a_6 * \text{cost}_K * \text{load}_m / \text{load}_K +$ ‘Cent East + LI
$a_7 * \text{cost}_K * \text{load}_m / \text{load}_K +$ ‘NYC + LI
$a_8 * \text{cost}_K * \text{load}_m / \text{load}_K$ ‘Cent East + LI + NYC

In all cases, the variables are:

a_1 = fraction of time when no constraints exist
a_2 = fraction of time when Central East interface alone is constraining
a_3 = fraction of time when Sprainbrook-Dunwoodie interface alone is constraining
a_4 = fraction of time when Con Ed-Long Island (including the Y49/Y50 lines) interfaces are constraining, but Central East and Sprainbrook-Dunwoodie

interfaces are not constraining

a_5 = fraction of time when Central East and Sprainbrook-Dunwoodie interfaces are constraining but Con Ed-Long Island (including the Y49 and Y50 lines) interfaces are not constraining

a_6 = fraction of time when Central East, Con Ed-Long Island interfaces (including the Y49/Y50 lines) are constraining but the Sprainbrook-Dunwoodie interface is not constraining

a_7 = fraction of time when Sprainbrook-Dunwoodie, Con Ed-Long Island interfaces (including the Y49/Y50 lines) are constraining but the Central East interface is not constraining

a_8 = fraction of time when Central East, Sprainbrook-Dunwoodie, Con Ed-Long Island interfaces (including the Y49/Y50 lines) are constraining

$cost_{A...K}$ = revenue deficiencies due toDER Aggregation Demand Reductions in Load Zones A…K, calculated on a hourly basis

$load_m$ = real-time Load for Transmission Customer m, calculated on an hourly basis

$load_{A...K}$ = real-time Loads for all Transmission Customers in Load Zones A…K, calculated on an hourly basis

24.2 Measurement of Actual Demand Reduction of Individual Distributed Energy Resources within a DER Aggregation

For the purposes of Demand Reduction calculations described in this Section, the metered load values of Distributed Energy Resources shall be zero or greater. The measured amount of Demand Reduction for each 6-second interval by an individual Distributed Energy Resource within a DER Aggregation which is dispatched for Energy with no Regulation Service shall be the greater of: (i) the Distributed Energy Resource's adjusted Economic Customer Baseline Load ("ECBL") for each five-minute interval, which shall be calculated in accordance with section 24.2.1 and ISO Procedures, minus the actual metered load for each 6-secondinterval and (ii) zero.

The measured amount of Demand Reduction for each 6-second interval by an individual Distributed Energy Resource within a DER Aggregation which is dispatched for Regulation Service shall be the greater of: (i) the Distributed Energy Resource's Baseline Load for each 6-second interval of Regulation Service, which shall be calculated in accordance with section

24.2.2 and ISO Procedures, minus the Distributed Energy Resource's telemetered load values for each 6-second interval and (ii) zero.

The amount of Demand Reduction supplied by a DER Aggregation shall be the sum of Demand Reductions from each individual Distributed Energy Resource within the DER Aggregation. Aggregators shall provide these DER Aggregation Demand Reductions to the ISO for each 6-second interval using real-time telemetry in accordance with Services Tariff section 13 and the ISO Procedures. Aggregators shall provide the DER Aggregation Actual Demand Reductions, determined based on revenue-quality meter data, to the ISO pursuant to this section 24.2, and in accordance with the ISO Procedures.

24.2.1 Methodology for the Calculating the Economic Customer Baseline Load for a Distributed Energy Resource within a DER Aggregation during Intervals with no Regulation Service Dispatch

The ISO shall employ two different calculation methodologies of the Economic Customer Baseline Load ("ECBL") for Demand Reductions, depending on whether the Demand Reduction is on a weekend or a weekday, during the intervals with no Regulation Service dispatch for the DER Aggregation.

24.2.1.1 Definitions

Adjusted Weekday ECBL: For each five-minute interval, the Adjusted Weekday ECBL shall be equal to the sum of the ECBL and the ECBL In-Day Adjustment Factor.

ECBL In-Day Adjustment Factor: The ECBL In-Day Adjustment shall be an adjustment that is applied to the ECBL for each five-minute interval.

a) Calculate the ECBL In-Day Adjustment by subtracting the average of the ECBL over the three five-minute intervals of the ECBL In-Day Adjustment Period from the average of the metered load for the same three five-minute intervals, provided that the DER Aggregation was not dispatched for Energy and/or Regulation Service, in any of the three five-minute intervals of the ECBL In-Day Adjustment Period.

b) If the DER Aggregation was dispatched for Energy and/or Regulation Service during one or more of the three five-minute intervals of the ECBL In-Day Adjustment Period, calculate the ECBL In-Day Adjustment by replacing the metered loads in step (a) above by the Proxy Load values for one or more of the three five-minute intervals of the ECBL In-Day Adjustment Period in which the DER Aggregation was dispatched for Energy and/or Regulation Service.

c) The ECBL In-Day Adjustment shall be limited to ± 20% of the ECBL value for the five-minute interval it is applied to.

ECBL In-Day Adjustment Period: The ECBL Adjustment Period is the time prior to the Demand Reduction period that is used to determine the ECBL In-Day Adjustment. The intervals to be used in the ECBL Adjustment Period shall be the three consecutive five-minute intervals starting 60 minutes prior to the first operating interval of dispatch and ending 45 minutes prior to the operating interval of dispatch. All the subsequent intervals of uninterrupted dispatch following the first interval of dispatch shall use the same ECBL In-Day Adjustment Period. The ECBL In-Day Adjustment Period shall be recalculated for every interval of dispatch which is preceded by an interval of non-dispatch.

ECBL Weekday Window: The ECBL Weekday Window is the time period reviewed in determining the ECBL for any five-minute interval that takes place on a weekday. It shall consist of the like-kind-five-minute intervals from the previous ten weekdays that correspond to each five-minute interval that is being calculated. Treatment of NERC holidays that occur on weekdays shall be equivalent to all intervals that take place on the weekend.

ECBL Weekend Window: The ECBL Weekend Window is the time period reviewed in determining the ECBL for any five-minute interval that takes place on a weekend. It shall consist of the like-kind intervals from the previous three weekend days of the same type (Saturday or Sunday) that correspond to each five-minute-interval. Treatment of NERC holidays that occur on weekend days shall be equivalent to all intervals that take place on the weekend.

Proxy Load: The Proxy Load for a five-minute interval is the adjusted ECBL for that interval calculated as per the instructions in Section 24.2.1.2 or 24.2.1.3.

24.2.1.2 Methodology for the Calculating the Economic Customer Baseline Load for Demand Reductions on a Weekday

To determine the ECBL for a five-minute interval (a "Target Interval") that occurs on a weekday:

a) Select the five-minute intervals that comprise the ECBL Weekday Window for that Target Interval.

b) Select the metered load value for each five-minute interval in the ECBL Weekday Window where the DER Aggregation was not dispatched for Energy and/or Regulation Service.

c) For each five-minute interval of the ECBL Weekday Window where the DER Aggregation was dispatched for Energy and/or Regulation Service, select the Proxy Load values for that five-minute interval and day in place of the actual metered load for that interval.

d) Rank in descending order the metered load and Proxy Load values determined in steps b and c.

e) Calculate the average of the fifth and sixth ranked values. The value as so calculated shall be the ECBL for the Target Interval.

f) Apply the ECBL In-Day Adjustment to the ECBL to determine the Adjusted Weekday ECBL for the Target Interval.

24.2.1.3 Methodology for the Calculating the Economic Customer Baseline Load for a Resource's Demand Reduction on a Weekend

To determine the ECBL for a Target Interval that occurs on a weekend:

a) Select the five-minute intervals that comprise the ECBL Weekend Window for the Target Interval.

b) Select the metered load value for each interval in the ECBL Weekend Window where the DER Aggregation was not dispatched for Energy and/or Regulation Service.

c) For each five-minute interval of the ECBL Weekend Window where the DER Aggregation was dispatched for Energy and/or Regulation Service, select the Proxy Load Value for that hour and day in place of the actual metered load for the interval.

d) Calculate the average of the metered load and ECBL Proxy Load values. The value so calculated is the ECBL for the Target Interval.

e) Apply the ECBL In-Day Adjustment Factor to the ECBL to calculate the Adjusted Weekend ECBL for the Target Interval.

24.2.2 Methodology for the Calculating the Baseline Load for a Distributed Energy Resource within a DER Aggregation during Intervals with Regulation Service Dispatch

For each 6-second interval during which a DER Aggregation is dispatched to provide Regulation Service, the Aggregator shall calculate the individual Distributed Energy Resource's Baseline Load as the Distributed Energy Resource's 6-second telemetered Load prior to the start of dispatch for Regulation Service. If the Aggregation was dispatched to provide Energy and no Regulation Service in the interval prior to being dispatched for Regulation Service, the Aggregator shall use the Proxy Load value corresponding to the five-minute interval immediately preceding the dispatch instruction as the Distributed Energy Resource's Baseline Load.

24.3 Verification of Actual Demand Reduction from DER Aggregations

Demand Reduction calculated using the methodology described in Section 24.2 is subject to verification by the ISO. Aggregators shall report the data at the time and in the format required by the ISO pursuant to Section 24.4. If an Aggregator fails to report the required data to the ISO in accordance with Section 24.4, the Aggregator will be subject to penalties associated with a failure to supply the Demand Reductions and may lose its eligibility to participate in a DER Aggregation. All Demand Reduction data are subject to audit by the ISO. If the ISO determines that it has made an erroneous payment to an Aggregator, it shall have the right to recover it either by reducing other payments to that Aggregator or by any other lawful means.

24.4 Data Reporting Requirements for Aggregators

Upon request, the Aggregator must submit to the ISO the information specified in this Section 24.4 for each Distributed Energy Resource in a DER Aggregation. The Aggregator must submit this information for the purpose of enrolling, registering, making settlements, and verifying the participation of each Distributed Energy Resource in the ISO's Energy market. If the Distributed Energy Resource has a Local Generator at its site, it must also have a meter, compliant with ISO standards and procedures, that measures the total output of the Local Generator, regardless of whether at initial enrollment the Local Generator is intended to be used to provide Demand Reduction in the DER Participation Model, provided that if the Local Generator is an Intermittent Power Resource, a meter that measures the total output of the Local Generator is not required..

24.4.1 Data Reporting Requirements for Enrollment of Distributed Energy Resources Participating within a DER Aggregation

The Aggregator shall provide to the ISO the following information for each Distributed Energy Resource that is seeking to enroll, either individually or collectively with other Distributed Energy Resources, as a DER Aggregation participating in the ISO's Energy market, which shall include providing information regarding each of the Distributed Energy Resource's interval meters required under Section 24.4:

a. Meter test criteria, as described in the Services Tariff Section 13 and the ISO Procedures;

b. Documentation to validate installation of interval meter equipment;

c. Interval metering installation individual, company, and professional engineering license information;

d. Make and model of installed interval metering device(s);

e. Accuracy of installed interval metering device(s);

f. Interval meter Current Transformer (CT) and Potential Transformer (PT) type designation, if applicable;

g. CT Ratio, if applicable;

h. Use of pulse data recorder as an interval metering device, if applicable;

i. Pulse data recorder multiplier, if applicable;

j. Any other type of meter multiplier used in the translation of data collected by the device for measuring demand, kWh, and/or MWh, if applicable;

k. Its service address;

l. Its Load Serving Entity;

m. Its Transmission Owner;

n. Its meter authority/Meter Services Entity;

o. Distributed Energy Resource's maximum Winter and Summer reduction MW;

p. Business classification of the Distributed Energy Resource (based on ISO-defined categories or national standards for business classification); and

q. A description of any Local Generator at its site, including the Local Generator's system, its primary fuel type, the year in which it was built, the year of any retrofit, its nameplate capacity, and its horsepower, if applicable.

24.4.2 Data Reporting Requirements for Verification of Demand Reductions of Distributed Energy Resources in the ISO's Energy and Ancillary Services Market

The Aggregator shall retain for purposes of an audit, and provide the ISO with the following required data from each interval meter required under Section 24.4 for each Distributed Energy Resource that is registered, either individually or collectively with other Distributed Energy Resources, as a DER Aggregation, to verify the calculated Demand Reduction of a Distributed Energy Resource in the ISO's Energy and Ancillary Services market:

a) Totalized net interval Demand Reduction data of the Distributed Energy Resource (*i.e.*, the net interval Demand Reduction data totalized across all Distributed

Energy Resources that are registered, either individually or collectively with other Distributed Energy Resources, as a DER Aggregation) for the period of the Demand Reduction of the Distributed Energy Resource in the format required for reporting to the ISO's Settlement Data Exchange application;

b) Five-minute-interval metered Load data for each of the individual Distributed Energy Resources that is registered as part of a single DER Aggregation, for all intervals of Demand Reduction for the period for which it was enrolled; and

c) Five-minute interval metered Load data for each of the individual Distributed Energy Resources that is registered as part of a single DER Aggregation, for all intervals of the period for which it was enrolled..

The Aggregator shall comply with the following when providing metering data to verify energy reductions of Distributed Energy Resources:

a) Section 7.4.1 of the ISO Services Tariff;

b) Section 13 of the ISO Services Tariff; and

c) The ISO's Meter Data Management Protocols as provided on the ISO's website.

24.4.3 Additional Data Required Upon Request

To verify the participation of each Distributed Energy Resource that is enrolled, either individually or collectively with other Distributed Energy Resources, as a DER Aggregation in the ISO's Energy market, Aggregators and/or their meter authority/Meter Services Entity shall provide the ISO upon the ISO's request such additional information that may be required, including, but not limited, to the following:

a) Any data reporting requirements of Attachments H and O to the ISO Services Tariff;

b) Any data reporting requirements of Section 3.4 of the ISO Services Tariff;

c) Historical Load documentation;

d) Load data history for Pre- and Post-Validation, Edit and Estimation (VEE);

e) Up to three months of historical Load data when enrolling a Demand Side Resource to participate in the ISO's Energy market;

f) New and existing metering documentation, including, but not limited to:

1. Calibration records;

2. Time check;

3. Sum check;

4. High/Low check; and

5. Zero value check.

31.2 Reliability Planning Process

31.2.1 Local Transmission Owner Planning Process

31.2.1.1 Scope

31.2.1.1.1 Criteria, Assumptions and Data

Each Transmission Owner will post on its website the planning criteria and assumptions currently used in its LTPP as well as a list of any applicable software and/or analytical tools currently used in the LTPP. Customers, Market Participants and other interested parties may review and comment on the planning criteria and assumptions used by each Transmission Owner, as well as other data and models used by each Transmission Owner in its LTPP. The Transmission Owners will take into consideration any comments received. Any planning criteria or assumptions for a Transmission Owner's BPTFs will meet or exceed any applicable NERC, NPCC or NYSRC criteria. The LTPP shall include a description of the needs addressed by the LTPP as well as the assumptions, applicable planning criteria and methodology utilized and the Public Policy Requirements considered. A link to each Transmission Owner's website will be posted on the ISO website.

31.2.1.1.2 Consideration of Transmission Needs Driven by Public Policy Requirements

31.2.1.1.2.1 Procedures for the Identification of Transmission Needs Driven by Public Policy Requirements in Local Transmission Plans and for the Consideration of Transmission Solutions

In developing its LTP, each Transmission Owner shall consider whether there is a transmission need on its system that is being driven by a Public Policy Requirement. The LTP will identify any transmission project included in the LTP as a solution to a transmission need being driven by a Public Policy Requirement. In evaluating potential transmission solutions, the

Transmission Owner will give consideration to the objectives of the Public Policy Requirement(s) driving the need for transmission.

31.2.1.1.2.2 Determination of Local Transmission Needs Driven by Public Policy Requirements

As part of its LTP process pursuant to Section 31.2.1.2 below, each Transmission Owner will consider whether there is a transmission need on its local system that is being driven by a Public Policy Requirement for which a local transmission solution should be evaluated, including needs proposed by market participants and other interested parties. A market participant or other interested party proposing a transmission need on a Transmission Owner's local system driven by a Public Policy Requirement shall submit its proposal to the ISO and the relevant Transmission Owner, and will identify the specific Public Policy Requirement that is driving the proposed transmission need and an explanation of why a local transmission upgrade is necessary to implement the Public Policy Requirement. Any proposed local system transmission need will be posted on the ISO website. The ISO will transmit proposed transmission needs on a Transmission Owner's local system driven by Public Policy Requirements to the NYDPS, with a request that the NYDPS review the proposals and provide the relevant Transmission Owner with input to assist the Transmission Owner in its determination. The Transmission Owner, after considering the input provided by the NYDPS and any information provided by a market participant or other party, will determine whether there are transmission needs driven by Public Policy Requirements for which local transmission solutions should be evaluated. The Transmission Owner will post on its website a list of the transmission needs driven by Public Policy Requirements for which local transmission solutions should be evaluated, with an explanation of why the Transmission Owner identified those transmission needs and declined to identify other proposed transmission needs.

31.2.1.1.2.3 Evaluation of Proposed Local Transmission Solutions

In evaluating potential transmission solutions, if any, the Transmission Owner will give consideration to the objectives of the Public Policy Requirement driving the need for a local transmission solution. The Transmission Owner will evaluate solutions to identified transmission needs, including transmission solutions proposed by market participants and other parties for inclusion in its LTP. The Transmission Owner, in consultation with the NYDPS, will evaluate proposed transmission solutions on its local system to determine the more efficient or cost-effective transmission solutions. The Transmission Owner will consider the relative costs and benefits of proposed transmission solutions and their impact on the Transmission Owner's transmission system and its customers. Any local transmission solution identified by the Transmission Owner through the LTP process will be reviewed with stakeholders as part of each Transmission Owner's regular LTP process and will be included in the Transmission Owner's subsequent LTP. In conducting its evaluation, the Transmission Owner will use criteria that are relevant to the Public Policy Requirement driving the transmission need, which may include its published local planning criteria and assumptions.

31.2.1.2 Process Timeline

31.2.1.2.1 Each Transmission Owner, in accordance with a schedule set forth in the ISO Procedures, will post its current LTP on its website for review and comment by interested parties sufficiently in advance of the time for submission to the ISO for input to its RNA so as to allow adequate time for stakeholder review and comment. Each LTP will include:

- identification of the planning horizon covered by the LTP,
- data and models used,

- reliability needs, needs driven by Public Policy Requirements, and other needs addressed,
- potential solutions under consideration, and,
- a description of the transmission facilities covered by the plan.

31.2.1.2.2 To the extent the current LTP utilizes data or inputs, related to the ISO's planning process, not already reported by the ISO in Form 715 and referenced on its website, any such data will be provided to the ISO at the time each Transmission Owner posts criteria and planning assumptions in accordance with Section 31.2.1.1 and will be posted by the ISO on its website subject to any confidentiality or Critical Energy Infrastructure Information restrictions or requirements.

31.2.1.2.3 Each planning cycle, the ISO shall hold one or more stakeholder meetings of the ESPWG and TPAS at which each Transmission Owner's current LTP will be discussed. Such meetings will be held either at the Transmission Owner's Transmission District, or at an ISO location. The ISO shall post notice of the meeting and shall disclose the agenda and any other material distributed prior to the meeting.

31.2.1.2.4 Interested parties may submit written comments to a Transmission Owner with respect to its current LTP within thirty days after the meeting. Each Transmission Owner shall list on its website, as part of its LTP, the person and/or location to which comments should be sent by interested parties. All comments will be posted on the ISO website. Each Transmission Owner will consider comments received in developing any modifications to its LTP. Any such modification will be explained in its current LTP posted on its website pursuant to

Section 31.2.1.2.2 above and discussed at the next meeting held pursuant to Section 31.2.1.2.3 above.

31.2.1.2.5 Each planning cycle, each Transmission Owner will submit the finalized portions of its current LTP to the ISO as contemplated in Section 31.2.2.4.2 below for timely inclusion in the RNA.

31.2.1.3 ISO Evaluation of Transmission Owner Local Transmission Plans in Relation to Regional and Local Transmission Needs

The ISO will review the Transmission Owner LTPs as they relate to the BPTFs as set forth in Section 31.2.2.4.2. The ISO will also evaluate whether a regional transmission solution – including, but not limited to, regional transmission solutions proposed by Developers pursuant to this Attachment Y – could satisfy an identified regional transmission need on the BPTFs that impacts more than one Transmission District more efficiently or more cost effectively than a local transmission solution identified in a Transmission Owner's LTP in accordance with Section 31.2.6.4.2 for the satisfaction of a regional Reliability Need, Section 31.3.1.3.6 for the reduction of congestion identified in CARIS, or Section 31.4.7.2 for the satisfaction of a Public Policy Transmission Need. The ISO will report the results of its evaluation solely for informational purposes in the relevant ISO planning report prepared under this Attachment Y, and the Transmission Owners shall not be required to revise their LTPs based on the results of the ISO's evaluation.

31.2.1.4 LTP Dispute Resolution Process

31.2.1.4.1 Disputes Related to the LTPP; Objective; Notice

Disputes related to the LTPP are subject to the DRP. The objective of the DRP is to assist parties having disputes in communicating effectively and resolving disputes as expeditiously as possible. Within fifteen (15) calendar days of the presentation by a Transmission Owner of its LTP to the ESPWG and TPAS, a party with a dispute shall notify in writing the Affected TO, the ISO, the ESPWG and TPAS of its intention to utilize the DRP. The notice shall identify the specific issue in dispute and describe in sufficient detail the nature of the dispute.

31.2.1.4.2 Review by the ESPWG/TPAS

The issue raised by a party with a dispute shall be reviewed and discussed at a joint meeting of the ESPWG and the TPAS in an effort to resolve the dispute. The party with a dispute and the Affected TO shall have an opportunity to present information concerning the issue in dispute to the ESPWG and the TPAS.

31.2.1.4.3 Information Discussions

To the extent the ESPWG and the TPAS are unable to resolve the dispute, the dispute will be subject to good faith informal discussions between the party with a dispute and the Affected TO. Each of those parties will designate a senior representative authorized to enter into informal discussions and to resolve the dispute. The parties to the dispute shall make a good faith effort to resolve the dispute through informal discussions as promptly as practicable.

31.2.1.4.4 Alternative Dispute Resolution

In the event that the parties to the dispute are unable to resolve the dispute through informal discussions within sixty (60) days, or such other period as the parties may agree upon, the parties may, by mutual agreement, submit the dispute to mediation or any other form of alternative dispute resolution. The parties shall attempt in good faith to resolve the dispute in accordance with a mutually agreed upon schedule but in no event may the schedule extend beyond ninety (90) days from the date on which the parties agreed to submit the dispute to alternative dispute resolution.

31.2.1.4.5 Notice of Results of Dispute Resolution

The Affected TO shall notify the ISO and ESPWG and TPAS of the results of the DRP and update its LTP to the extent necessary. The ISO shall use in its planning process the LTP provided by the Affected TO.

31.2.1.4.6 Rights Under the Federal Power Act

Nothing in the DRP shall affect the rights of any party to file a complaint with the Commission under relevant provisions of the FPA.

31.2.1.4.7 Confidentiality

All information disclosed in the course of the DRP shall be subject to the same protections accorded to confidential information and CEII by the ISO under its confidentiality and CEII policies.

31.2.2 Reliability Needs Assessment

31.2.2.1 General

The ISO shall prepare and publish the RNA as described below. The RNA will identify Reliability Needs. The ISO shall also designate in the RNA the Responsible Transmission Owner with respect to each Reliability Need.

31.2.2.2 Interested Party Participation in the Development of the RNA

The ISO shall develop the RNA in consultation with Market Participants and all other interested parties. TPAS will have responsibility consistent with ISO Procedures for review of the ISO's reliability analyses. ESPWG will have responsibility consistent with ISO Procedures for providing commercial input and assumptions to be used in the development of reliability assessment scenarios provided under Section 31.2.2.5, and in the reporting and analysis of historic congestion costs. Coordination and communication will be established and maintained between these two groups and ISO staff to allow Market Participants and other interested parties to participate in a meaningful way during each stage of the CSPP. The ISO staff shall report any majority and minority views of these collaborative governance work groups when it submits the RNA to the Operating Committee for a vote, as provided below.

31.2.2.3 Preparation of the Reliability Needs Assessment

31.2.2.3.1 The ISO shall evaluate bulk power system needs in the RNA over the Study Period.

31.2.2.3.2 The starting point for the development of the RNA Base Case will be the system as defined for the FERC Form No. 715 Base Case. The ISO shall develop this system representation to be used for its evaluations of the Study Period by primarily using: (1) the most recent NYISO Load and Capacity Data Report published by the ISO on its web site; (2) the most recent versions of ISO reliability analyses and assessments provided for or published by NERC, NPCC, NYSRC, and neighboring Control Areas; (3) information reported by neighboring Control Areas such as power flow data, forecasted load, significant new or modified generation and transmission facilities, and anticipated system conditions that the ISO determines may impact the BPTFs; and (4) data submitted pursuant to paragraph 31.2.2.4 below; *provided, however,* the ISO shall not include in the RNA Base Case an Interim Service Provider, an RMR Generator, or any other interim Generator Deactivation Solution selected by the ISO pursuant to

Attachment FF of the ISO OATT; *provided, further*, the ISO will include in the RNA Base Case a permanent transmission Generator Deactivation Solution selected by the ISO pursuant to Attachment FF of the ISO OATT if it meets the base case inclusion requirements in the ISO Procedures. The details of the development of the RNA Base Case are contained in the ISO Procedures. The RNA Base Case shall also include Interregional Transmission Projects that have been approved by the NYPSC transmission siting process and meet the base case inclusion requirements in the ISO Procedures.

31.2.2.3.3 The ISO shall assess the RNA Base Case to determine whether the BPTFs meet all Reliability Criteria for both resource and transmission adequacy in each year, and report the results of its evaluation in the RNA. Transmission analyses will include thermal, voltage, short circuit, and stability studies. Then, if any Reliability Criteria are not met in any year, the ISO shall perform additional analyses to determine whether additional resources and/or transmission capacity expansion are needed to meet those requirements, and to determine the Target Year of need for those additional resources and/or transmission. A short circuit assessment will be performed for the tenth year of the Study Period. The study will not seek to identify specific additional facilities. Reliability Needs will be defined in terms of total deficiencies relative to Reliability Criteria and not necessarily in terms of specific facilities.

31.2.2.4 Planning Participant Data Input

31.2.2.4.1 At the ISO's request, Market Participants, Developers, and other parties shall provide, in accordance with the schedule set forth in the ISO Procedures, the data necessary for the development of the RNA. This data will include but not be limited to (1) existing and planned additions to the New York State Transmission System (to be provided by Transmission Owners and municipal electric utilities); (2) proposals for Merchant Transmission Facilities (to be provided by merchant transmission Developers); (3) generation additions and retirements (to be provided by generator owners, Aggregators and Developers); (4) demand response programs (to be provided by demand response providers); and (5) any long-term firm transmission requests made to the ISO.

31.2.2.4.2 The Transmission Owners shall submit their current LTPs referenced in Section 31.1.3 and Section 31.2.1 to the ISO. The Transmission Owners and the ISO will coordinate with each other in reviewing the LTPs. The ISO will review the Transmission Owners' LTPs, as they relate to BPTFs, to determine whether they will meet reliability needs identified in the LTPs, recommend an alternate means to resolve the local needs from a regional perspective pursuant to Section 31.2.6.4, and indicate if it is not in agreement with a Transmission Owner's proposed additions. The ISO shall report its determinations under this section in the RNA and in the CRP.

31.2.2.4.3 All data received from Market Participants, Developers, and other parties shall be considered in the development of the system representation for the Study Period in accordance with the ISO Procedures.

31.2.2.5 Reliability Scenario Development

The ISO, in consultation with the ESPWG and TPAS, shall develop reliability scenarios addressing the Study Period. Variables for consideration in the development of these reliability scenarios include but are not limited to: load forecast uncertainty, fuel prices and availability, new resources, retirements, transmission network topology, and limitations imposed by proposed environmental or other legislation.

31.2.2.6 Evaluation of Reliability Scenarios

The ISO will conduct additional reliability analyses for the reliability scenarios developed pursuant to paragraph 31.2.2.5. These evaluations will test the robustness of the needs assessment studies conducted under paragraphs 31.2.2.3. This evaluation will only identify conditions under which Reliability Criteria may not be met. It will not identify or propose additional Reliability Needs. In addition, the ISO will perform appropriate sensitivity studies to determine whether Reliability Needs previously identified can be mitigated through alternate system configurations or operational modes. The Reliability Needs may increase in some reliability scenarios and may decrease, or even be eliminated, in others. The ISO shall report the results of these evaluations in the RNA.

31.2.2.7 Consequences for Other Regions

The ISO will coordinate with the ISO/RTO Regions to identify the consequences of the reliability transmission projects on such ISO/RTO Regions using the respective planning criteria of such ISO/RTO Regions. The ISO shall report the results in the CRP. The ISO shall not bear the costs of required upgrades in another region.

31.2.2.8 Reliability Needs Assessment Report Preparation

Once all the analyses described above have been completed, ISO staff will prepare a draft of the RNA including discussion of its assumptions, Reliability Criteria, and results of the analyses and, if necessary, designate the Responsible Transmission Owner. One or more compensatory MW/ Load adjustment scenarios will be developed by the ISO as a guide to the development of proposed solutions to meet the identified Reliability Need.

31.2.3 RNA Review Process

31.2.3.1 Collaborative Governance Process

The draft RNA shall be submitted to both TPAS and the ESPWG for review and comment. The ISO shall make available to any interested party sufficient information to replicate the results of the draft RNA. The information made available will be electronically masked and made available pursuant to a process that the ISO reasonably determines is necessary to prevent the disclosure of any Confidential Information or Critical Energy Infrastructure Information contained in the information made available. Market Participants and other interested parties may submit at any time optional suggestions for changes to ISO rules or procedures which could result in the identification of additional resources or market alternatives suitable for meeting Reliability Needs. Following completion of the TPAS and ESPWG review, the draft RNA reflecting the revisions resulting from the TPAS and ESPWG review, shall be forwarded to the Operating Committee for discussion and action. The ISO shall notify the Business Issues Committee of the date of the Operating Committee meeting at which the draft RNA is to be presented. Following the Operating Committee vote, the draft RNA will be transmitted to the Management Committee for discussion and action.

31.2.3.2 Board Action

Following the Management Committee vote, the draft RNA, with working group, Operating Committee, and Management Committee input, will be forwarded to the ISO Board for review and action. Concurrently, the draft RNA will be provided to the Market Monitoring Unit for its review and consideration of whether market rules changes are necessary to address an identified failure, if any, in one of the ISO's competitive markets. The Board may approve the RNA as submitted, or propose modifications on its own motion. If any changes are proposed by the Board, the revised RNA shall be returned to the Management Committee for comment. The Board shall not make a final determination on a revised RNA until it has reviewed the Management Committee comments. Upon approval by the Board, the ISO shall issue the final RNA to the marketplace by posting it on its web site.

The responsibilities of the Market Monitoring Unit that are addressed in the above section of this Attachment are also addressed in Section 30.4.6.8.2 of the Market Monitoring Plan, Attachment O to the ISO Services Tariff.

31.2.3.3 Needs Assessment Disputes

Notwithstanding any provision to the contrary in this Attachment, the ISO OATT, or the NYISO Services Tariff, in the event that a Market Participant raises a dispute solely within the NYPSC's jurisdiction relating to the final conclusions or recommendations of the RNA, a Market Participant may refer such dispute to the NYPSC for resolution. The NYPSC's final determination shall be binding, subject only to judicial review in the courts of the State of New York pursuant to Article 78 of the NYCPLR.

31.2.3.4 Public Information Sessions

In order to provide ample exposure for the marketplace to understand the identified Reliability Needs, the ISO will provide various opportunities for Market Participants and other potentially interested parties to discuss the final RNA. Such opportunities may include presentations at various ISO Market Participant committees, focused discussions with various industry sectors, and/or presentations in public venues.

31.2.4 Development of Solutions to Reliability Needs

31.2.4.1 Eligibility and Qualification Criteria for Developers and Projects

For purposes of fulfilling the requirements of the Developer qualification criteria in this Section 31.2.4.1 and its subsections, the term “Developer” includes Affiliates, as that term is defined in Section 2 of the ISO Services Tariff and Section 1 of the ISO OATT. To the extent that a Developer relies on Affiliate(s) to satisfy any or all of the qualification criteria set forth in Section 31.2.4.1.1.1, the Affiliate(s) shall provide to the ISO: (i) the information required in Section 31.2.4.1.1.1 to demonstrate its capability to satisfy the applicable qualification criteria, and (ii) a notarized officer’s certificate, signed by an authorized officer of the Affiliate with signatory authority, in a form acceptable to the ISO, certifying that the Affiliate will participate in the Developer’s project in the manner described by the Developer and will abide by the requirements set forth in this Attachment Y, the ISO Tariffs, and ISO Procedures related and applicable to the Affiliate’s participation.

31.2.4.1.1 Developer Qualification and Timing

The ISO shall provide each Developer with an opportunity to demonstrate that it has or can draw upon the financial resources, technical expertise, and experience needed to finance, develop, construct, operate and maintain a transmission project to meet identified Reliability Needs. The ISO shall consider the qualifications of each Developer in an evenhanded and non-discriminatory manner, treating Transmission Owners and Other Developers alike.

31.2.4.1.1.1 Developer Qualification Criteria

The ISO shall make a determination on the qualification of a Developer to propose to develop a transmission project as a solution to an identified Reliability Need based on the following criteria:

31.2.4.1.1.1.1 The technical and engineering qualifications and experience of the Developer relevant to the development, construction, operation and maintenance of a transmission facility, including evidence of the Developer's demonstrated capability to adhere to standardized construction, maintenance, and operating practices and to contract with third parties to develop, construct, maintain, and/or operate transmission facilities;

31.2.4.1.1.1.2 The current and expected capabilities of the Developer to develop and construct a transmission facility and to operate and maintain it for the life of the facility. If the Developer has previously developed, constructed, maintained or operated transmission facilities, the Developer shall provide the ISO a description of the transmission facilities (not to exceed ten) that the Developer has previously developed, constructed, maintained or operated and the status of those facilities, including whether the construction was completed, whether the facility entered into commercial operations, whether the facility has been suspended or terminated for any reason, and evidence demonstrating the ability of the Developer to address and timely remedy any operational failure of the facilities; and

31.2.4.1.1.1.3 The Developer's current and expected capability to finance, or its experience in arranging financing for, transmission facilities. For purposes of the ISO's determination, the Developer shall provide the ISO:

(1) evidence of its demonstrated experience financing or arranging financing for transmission facilities, if any, including a description of such projects (not to exceed ten) over the previous ten years, the capital costs and financial structure of such projects, a description of any financing obtained for these projects through

rates approved by the Commission or a state regulatory agency, the financing closing date of such projects, and whether any of the projects are in default;

(2) its audited annual financial statements from the most recent three years and its most recent quarterly financial statement, or equivalent information;

(3) its credit rating from Moody's Investor Services, Standard & Poor's, or Fitch, or equivalent information, if available;

(4) a description of any prior bankruptcy declarations, material defaults, dissolution, merger or acquisition by the Developer or its predecessors or subsidiaries occurring within the previous five years; and

(5) such other evidence that demonstrates its current and expected capability to finance a project to solve a Reliability Need.

31.2.4.1.1.1.4 A detailed plan describing how the Developer – in the absence of previous experience financing, developing, constructing, operating, or maintaining transmission facilities – will finance, develop, construct, operate, and maintain a transmission facility, including the financial, technical, and engineering qualifications and experience and capabilities of any third parties with which it will contract for these purposes.

31.2.4.1.1.2 Developer Qualification Determination

Any Developer seeking to become qualified may submit the required information, or update any previously submitted information, at any time. The ISO shall treat on a confidential basis in accordance with the requirements of its Code of Conduct in Attachment F of the ISO OATT any non-public financial qualification information that is submitted to the ISO by the Developer under Section 31.2.4.1.1.1.3 and is designated by the Developer as "Confidential

Information." The ISO shall within 15 days of a Developer's submittal, notify the Developer if the information is incomplete. If the submittal is deemed incomplete, the Developer shall submit the additional information within 30 days of the ISO's request. The ISO shall notify the Developer of its qualification status within 30 days of receiving all necessary information. A Developer shall retain its qualification status for a three-year period following the notification date; *provided, however*, that the ISO may revoke this status if it determines that there has been a material change in the Developer's qualifications and the Developer no longer meets the qualification requirements. A Developer that has been qualified shall inform the ISO within thirty days of any material change to the information it provided regarding its qualifications and shall submit to the ISO each year its most recent audited annual financial statement when available. At the conclusion of the three-year period or following the ISO's revocation of a Developer's qualification status, the Developer may re-apply for a qualification status under this section.

Any Developer determined by the ISO to be qualified under this section shall be eligible to propose a regulated transmission project as a solution to an identified Reliability Need and shall be eligible to use the cost allocation and cost recovery mechanism for regulated transmission projects set forth in Section 31.5 of this Attachment Y and Rate Schedule 10, Section 6.10, of the ISO OATT for any approved project.

31.2.4.2 Interregional Transmission Projects

Interregional Transmission Projects may be proposed under Section 31.2.5.1 of this Attachment Y as regulated backstop solutions, alternative regulated solutions, or market-based solutions, in response to a request by the ISO for solutions to a Reliability Need under the relevant provisions of Section 31.2.4. Interregional Transmission Projects proposed as regulated backstop solutions, alternative regulated solutions or market-based solutions shall be: (i) evaluated by the ISO in accordance with the applicable requirements of the reliability planning process of this Attachment Y, and (ii) jointly evaluated by the ISO and the relevant adjacent transmission planning region(s) in accordance with Section 7.3 of the Interregional Planning Protocol.

31.2.4.3 Regulated Backstop Solutions

31.2.4.3.1 When a Reliability Need is identified in any RNA issued under this tariff, the ISO shall request and the Responsible Transmission Owner shall provide to the ISO, as set forth in Section 31.2.5 below, a proposal for a regulated solution or combination of solutions that shall serve as a backstop to meet the Reliability Need if requested by the ISO due to the lack of sufficient viable market-based solutions to meet such Reliability Needs identified for the Study Period. The Responsible Transmission Owner shall be eligible to recover its costs for developing its proposal and seeking necessary approvals under Rate Schedule 10 of the ISO OATT. Regulated backstop solutions may include generation, transmission, or demand side resources. Such proposals may include reasonable alternatives that would effectively address the Reliability Need; provided however, the Responsible Transmission Owner’s obligation to propose and implement regulated backstop solutions under this tariff is limited to regulated transmission solutions. Prior to providing its response to the RNA, each Responsible Transmission Owner will present for discussion at the ESPWG and TPAS any updates in its LTP that impact a Reliability Need identified in the RNA. The ISO will present at the ESPWG and TPAS any updates to its determination under Section 31.2.2.4.2 with respect to the Transmission Owners' LTPs. Should more than one regulated backstop solution be proposed by a Responsible Transmission Owner to address a Reliability Need, it will be the responsibility of that Responsible Transmission Owner to determine which of the regulated backstop solutions will proceed following a finding by the ISO under Section 31.2.8 of this Attachment Y. The determination by the Responsible Transmission Owner will be made prior to the approval of the CRP which precedes the Trigger Date for the regulated backstop solution with the longest lead time. Contemporaneous with the request to the Responsible Transmission Owner, the ISO shall solicit market-based and alternative regulated responses as set forth in Sections 31.2.4.5 and 31.2.4.7, which shall not be a formal RFP process.

31.2.4.4 Qualifications for Regulated Backstop Solutions

31.2.4.4.1 The submission of a regulated backstop solution to a Reliability Need for purposes of the ISO's evaluation under Section 31.2.5 of the viability and sufficiency of the proposed solution and the determination of the Trigger Date for the proposed solution shall include, at a minimum, the following details: (1) contact information; (2) the lead time necessary to complete the project, including, if available, the construction windows in which the Responsible Transmission Owner can perform construction and what, if any, outages may be required during these periods; (3) a description of the project, including type, size, and geographic and electrical location, as well as planning and engineering specifications and drawings as appropriate; (4) evidence of a commercially viable technology, (5) a major milestone schedule; (6) the schedule for obtaining any permits and other certifications, if available; (7) status of ISO interconnection studies and interconnection agreement, if available; and (8) status of equipment availability and procurement, if available.

31.2.4.4.2 The submission of a regulated backstop solution to a Reliability Need for purposes of the ISO's evaluation of the proposed solution for possible selection as the more efficient or cost effective solution to the Reliability Need shall include, at a minimum, the following details: (1) updates to the information required under Section 31.2.4.4.1; (2) the schedule for obtaining required permits and other certifications; (3) a demonstration of Site Control or a schedule for obtaining such control; (4) the status of any contracts (other than an interconnection agreement) that are under negotiation or in place, including any contracts with third-party contractors; (5) status of ISO interconnection studies and interconnection agreement; (6) status of equipment availability and procurement; (7) evidence of financing or ability to finance the project; (8) capital cost estimates for the project; (9) a description of permitting or other risks facing the project at the stage of project development, including evidence of the reasonableness of project cost estimates, all based on the information available at the time of the submission; and (10) any other information requested by the ISO.

A Responsible Transmission Owner shall submit the following information to indicate the status of any contracts: (i) copies of all final contracts the ISO determines are relevant to its consideration, or (ii) where one or more contracts are pending, a timeline on the status of discussions and negotiations with the relevant documents and when the negotiations are expected to be completed. The final contracts shall be submitted to the ISO when available. The ISO shall treat on a confidential basis in accordance with the requirements of its Code of Conduct in Attachment F of the ISO OATT any contract that is submitted to the ISO and is designated by the Responsible Transmission Owner as "Confidential Information."

A Responsible Transmission Owner shall submit the following information to indicate the status of any required permits: (i) copies of all final permits received that the ISO determines are relevant to its consideration, or (ii) where one or more permits are pending, the completed permit application(s) with information on what additional actions must be taken to meet the permit requirements and a timeline providing the expected timing for finalization and receipt of the final permit(s). The final permits shall be submitted to the ISO when available.

A Responsible Transmission Owner shall submit the following information, as appropriate, to indicate evidence of financing by it or any Affiliate upon which it is relying for financing: (i) evidence of self-financing or project financing through approved rates or the ability to do so, (ii) copies of all loan commitment letter(s) and signed financing contract(s), or (iii) where such financing is pending, the status of the application for any relevant financing, including a timeline providing the status of discussions and negotiations of relevant documents and when the negotiations are expected to be completed. The final contracts or approved rates shall be submitted to the ISO when available.

Upon the completion of any interconnection study or transmission expansion study of a proposed regulated backstop solution that is performed under Sections 3.7 or 4.5 of the ISO OATT or Attachments P or X of the ISO OATT, the Responsible Transmission Owner of the proposed project shall notify the ISO that the study has been completed and, at the ISO's request, shall submit to the ISO any study report and related materials prepared in connection with the study.

31.2.4.4.3 If the regulated backstop solution does not meet the Reliability Needs , the ISO will provide sufficient information to the Responsible Transmission Owner to determine how the regulated backstop should be modified to meet the identified Reliability Needs. The Responsible Transmission Owner will make necessary changes to its proposed regulated backstop solution to address reliability deficiencies identified by the ISO, and submit a revised proposal to the ISO for review and approval.

31.2.4.5 Market-Based Responses

At the same time that a proposal for a regulated backstop solution is requested from the Responsible Transmission Owner under Section 31.2.4.3, the ISO shall also request market-based responses from the market place. Subject to the execution of appropriately drawn confidentiality agreements and the Commission's standards of conduct, the ISO and the appropriate Transmission Owner or Transmission Owners shall provide any party who wishes to develop such a response access to the data that is necessary to develop its response. Such data shall only be used for the purposes of preparing a market-based response to a Reliability Need under this section. Such responses will be open on a comparable basis to all resources, including generation, demand response providers, and merchant transmission Developers.

31.2.4.6 Qualifications for a Valid Market-Based Response

The submission of a proposed market-based solution must include, at a minimum: (1) contact information; (2) the lead time necessary to complete the project, including, if available, the construction windows in which the Developer can perform construction and what, if any, outages may be required during these periods; (3) a description of the project, including type, size, and geographic and electrical location, as well as planning and engineering specifications and drawings as appropriate; (4) evidence of a commercially viable technology; (5) a major milestone schedule; (6) a schedule for obtaining any required permits and other certifications; (7) a demonstration of Site Control or a schedule for obtaining Site Control; (8) the status of any contracts (other than an interconnection agreement) that are under negotiation or in place; (9) the status of ISO interconnection studies and interconnection agreement; (10) the status of equipment availability and procurement; (11) evidence of financing or ability to finance the project; and (12) any other information requested by the ISO.

A Developer shall submit the following information to indicate the status of any contracts: (i) copies of all final contracts the ISO determines are relevant to its consideration, or (ii) where one or more contracts are pending, a timeline on the status of discussions and negotiations with the relevant documents and when the negotiations are expected to be completed. The final contracts shall be submitted to the ISO when available. The ISO shall treat on a confidential basis in accordance with the requirements of its Code of Conduct in Attachment F of the ISO OATT any contract that is submitted to the ISO and is designated by the Developer as "Confidential Information."

A Developer shall submit the following information to indicate the status of any required permits: (i) copies of all final permits received that the ISO determines are relevant to its consideration, or (ii) where one or more permits are pending, the completed permit application(s) with information on what additional actions must be taken to meet the permit requirements and a timeline providing the expected timing for finalization and receipt of the final permit(s). The final permits shall be submitted to the ISO when available.

A Developer shall submit the following information, as appropriate, to indicate evidence of financing by it or any Affiliate upon which it is relying for financing: (i) copies of all loan commitment letter(s) and signed financing contract(s), or (ii) where such financing is pending, the status of the application for any relevant financing, including a timeline providing the status of discussions and negotiations of relevant documents and when the negotiations are expected to be completed. The final contracts shall be submitted to the ISO when available.

Upon the completion of any interconnection study or transmission expansion study of a proposed market-based solution that is performed under Sections 3.7 or 4.5 of the ISO OATT or Attachments P or X of the ISO OATT, the Developer of the proposed project shall notify the ISO that the study has been completed and, at the ISO's request, shall submit to the ISO any study report and related materials prepared in connection with the study.

Failure to provide any data requested by the ISO within the timeframe set forth in Section 31.2.5.1 of this Attachment Y will result in the rejection of the proposed market-based solution from further consideration during that planning cycle.

31.2.4.7 Alternative Regulated Responses

31.2.4.7.1 The ISO will request alternative regulated responses to Reliability Needs at the same time that it requests market-based responses and regulated backstop solutions. Such proposals may include reasonable alternatives that would effectively address the identified Reliability Need.

31.2.4.7.2 In response to the ISO's request, Other Developers may develop alternative regulated proposals for generation, demand side alternatives, and/or other solutions to address a Reliability Need and submit such proposals to the ISO. Transmission Owners, at their option, may submit additional proposals for regulated solutions to the ISO. Transmission Owners and Other Developers may submit such proposals to the NYDPS for review at any time. Subject to the execution of appropriately drawn confidentiality agreements and the Commission's standards of conduct, the ISO and the appropriate Transmission Owner(s) shall provide Other Developers access to the data that is needed to develop their proposals. Such data shall be used only for purposes of preparing an alternative regulated proposal in response to a Reliability Need.

31.2.4.8 Qualifications for Alternative Regulated Solutions

31.2.4.8.1 The submission of an alternative regulated solution to a Reliability Need for purposes of the ISO's evaluation under Section 31.2.5 of the viability and sufficiency of the proposed solution and the determination of the Trigger Date for the proposed solution shall include, at a minimum, the following details: (1) contact information; (2) the lead time necessary to complete the project, including, if available, the construction windows in which the Other Developer or Transmission Owner can perform construction and what, if any, outages may be required during these periods; (3) a description of the project, including type, size, and geographic and electrical location, as well as planning and engineering specifications and drawings as appropriate; (4) evidence of a commercially viable technology; (5) a major milestone schedule; (6) the schedule for obtaining any permits and other certifications, if available; (7) status of ISO interconnection studies and interconnection agreement, if available; and (8) status of equipment availability and procurement, if available.

31.2.4.8.2 The submission of a proposed alternative regulated solution to a Reliability Need for purposes of the ISO's evaluation of the proposed solution for possible selection as the more efficient or cost effective solution for the Reliability Need must include, at a minimum: (1) updates to the information required under Section 31.2.4.8.1; (2) a demonstration of Site Control or a schedule for obtaining Site Control; (3) the status of any contracts (other than an Interconnection Agreement) that are under negotiation or in place, including any contracts with third-party contractors; (4) the status of any interconnection studies and interconnection agreement; (5) the schedule for obtaining any required permits and other certifications; (6) the status of equipment availability and procurement; (7) evidence of financing or ability to finance the project; (8) capital cost estimates for the project; (9) a description of permitting or other risks facing the project at the stage of project development, including evidence of the reasonableness of project cost estimates, all based on the information available at the time of the submission; and (10) any other information requested by the ISO.

An Other Developer or Transmission Owner shall submit the following information to indicate the status of any contracts: (i) copies of all final contracts the ISO determines are relevant to its consideration, or (ii) where one or more contracts are pending, a timeline on the status of discussions and negotiations with the relevant documents and when the negotiations are expected to be completed. The final contracts shall be submitted to the ISO when available. The ISO shall treat on a confidential basis in accordance with the requirements of its Code of Conduct in Attachment F of the ISO OATT any contract that is submitted to the ISO and is designated by the Other Developer or Transmission Owner as "Confidential Information."

An Other Developer or Transmission Owner shall submit the following information to indicate the status of any required permits: (i) copies of all final permits received that the ISO determines are relevant to its consideration, or (ii) where one or more permits are pending, the completed permit application(s) with information on what additional actions must be taken to meet the permit requirements and a timeline providing the expected timing for finalization and receipt of the final permit(s). The final permits shall be submitted to the ISO when available.

An Other Developer or Transmission Owner shall submit the following information, as appropriate, to indicate evidence of financing by it or any Affiliate upon which it is relying for financing: (i) evidence of self-financing or project financing through approved rates or the ability to do so, (ii) copies of all loan commitment letter(s) and signed financing contract(s), or (iii) where such financing is pending, the status of the application for any relevant financing, including a timeline providing the status of discussions and negotiations of relevant documents and when the negotiations are expected to be completed. The final contracts or approved rates shall be submitted to the ISO when available.

Upon the completion of any interconnection study or transmission expansion study of a proposed alternative regulated solution that is performed under Sections 3.7 or 4.5 of the ISO OATT or Attachments P or X of the ISO OATT, the Other Developer or Transmission Owner of the proposed project shall notify the ISO that the study has been completed and, at the ISO's request, shall submit to the ISO any study report and related materials prepared in connection with the study.

31.2.4.8.3 Failure to provide any data requested by the ISO within the timeframe provided in Sections 31.2.5.1 and 31.2.6.1 of this Attachment Y will result in the rejection of the proposed alternative regulated solution from further consideration during that planning cycle. A proponent of a proposed alternative regulated solution must notify the ISO immediately of any material change in status of a proposed alternative regulated solution. For purposes of this provision, a material change includes, but is not limited to, a change in the financial viability of the developer, a change in the siting status of the project, or a change in a major element of the project's development. If the ISO, at any time, learns of a material change in the status of a proposed alternative regulated solution, it may, at that time, make a determination as to the continued viability of the proposed alternative regulated solution.

31.2.4.9 Additional Solutions

Should the ISO determine that it has not received adequate regulated backstop or market-based solutions to satisfy the Reliability Need, the ISO may, in its discretion, solicit additional regulated backstop or market-based solutions. Other Developers or Transmission Owners may submit additional alternative regulated solutions for the ISO's consideration at that time.

31.2.5 ISO Evaluation of Viability, Sufficiency, and Trigger Date of Proposed Solutions to Reliability Needs

31.2.5.1 Timing for Submittal of Project Information and Developer Qualification Information and Opportunity to Provide Additional Information

Within 60 days after a request for solutions to a Reliability Need is made by the ISO after completion of the RNA, which time period may be extended by the ISO pursuant to Section 31.1.8.7, all Developers proposing solutions to an identified Reliability Need shall submit to the ISO for purposes of its evaluation the project information, as applicable, for: (i) a proposed regulated backstop solution under Section 31.2.4.4.1, (ii) a proposed market-based solution under Section 31.2.4.6, or (iii) a proposed alternative regulated solution under Section 31.2.4.8.1 of this Attachment Y. In response to a solicitation for a solution to a Reliability Need identified after the 2014-2015 planning cycle, the Developer of a proposed transmission solution must also demonstrate to the ISO, simultaneous with its submission of project information, that it has submitted a Transmission Interconnection Application or Interconnection Request, as applicable.

Any Developer that the ISO has determined under Section 31.2.4.1.1.2 or as set forth in this Section 31.2.5.1 below to be qualified to propose to develop a project as a transmission solution to an identified Reliability Need may submit the required project information; *provided, however,* that: (i) the Developer shall provide a non-refundable application fee of $10,000 and (ii) based on the actual identified need, the ISO may request that the qualified Developer provide additional Developer qualification information. Any Developer that has not been determined by the ISO to be qualified, but that wants to propose to develop a project, must submit to the ISO the information required for Developer qualification under Section 31.2.4.1.1 within 30 days after a request for solutions is made by the ISO. The ISO shall within 30 days of a Developer's submittal of its Developer qualification information, notify the Developer if this information is incomplete. The Developer shall submit additional Developer qualification information or project information required by the ISO within 15 days of the ISO's request. A Developer that fails to submit the additional Developer qualification information or the required project information will not be eligible for its project to be considered in that planning cycle.

31.2.5.2 Comparable Evaluation of All Proposed Solutions

The ISO shall evaluate: (i) any proposed market-based solution submitted by a Developer pursuant to Section 31.2.4.5, (ii) any proposed regulated backstop solution submitted by a Responsible Transmission Owner pursuant to Section 31.2.4.3, and (iii) any proposed alternative regulated solution submitted by a Transmission Owner or Other Developer pursuant to Section 31.2.4.7. The ISO will evaluate whether each proposed solution is viable and is sufficient to satisfy the identified Reliability Need by the need date pursuant to Sections 31.2.5.3 and 31.2.5.4. The proposed solutions may include multiple components and resource types. When evaluating proposed solutions to Reliability Needs from any Developer, all resource types – generation, transmission, demand response, or a combination of these resource types – shall be considered on a comparable basis as potential solutions to the Reliability Needs identified. All solutions will be evaluated in the same general time frame.

31.2.5.3 Evaluation of Viability of Proposed Solution

The ISO will determine the viability of a solution – transmission, generation, demand response, or a combination of these resource types – proposed to satisfy a Reliability Need. For purposes of its analysis, the ISO will evaluate whether: (i) the Developer has provided the required Developer qualification data pursuant to Section 31.2.4.1 and the required project information data under Sections 31.2.4.4.1, 31.2.4.6, or 31.2.4.8.1; (ii) the proposed solution is technically practicable; (iii) the Developer has indicated possession of, or an approach for acquiring, any necessary rights-of-way, property, and facilities that will make the proposal reasonably feasible in the required timeframe; and (iv) the proposed solution can be completed in the required timeframe. If the ISO determines that the proposed solution is not viable and, for regulated solutions, the Developer does not address any identified deficiency pursuant to Section 31.2.5.6, the ISO shall reject the proposed solution from further consideration during that planning cycle.

31.2.5.4 Evaluation of Sufficiency of Proposed Solution

The ISO will perform a comparable analysis of each proposed solution – transmission, generation, demand response, or a combination of these resource types – through the Study Period to identify whether it satisfies the Reliability Need(s). The ISO will evaluate each solution to determine whether the solution proposed by the Developer fully eliminates the Reliability Need(s). If the ISO determines that a proposed regulated solution is not sufficient and the Developer does not address any identified deficiency pursuant to Section 31.2.5.6, the ISO shall reject the proposed regulated solution from further consideration during that planning cycle.

31.2.5.5 Establishment of Trigger Date of Proposed Regulated Solutions

Upon receipt of all Developers' proposed regulated solutions pursuant to Section 31.2.5.1, the ISO will notify all Developers if any Developer has proposed a lead time for the implementation of its regulated solution that could result in a Trigger Date for the regulated solution within thirty-six months of the date of the ISO's presentation of the Viability and Sufficiency Assessment to the ESPWG, provided that the ISO will not disclose the identity of such Developer or the details of its project at that time. The ISO will independently analyze the lead time proposed by each Developer for the implementation of its regulated solution. The ISO will use the Developer's estimate and the ISO's analysis to establish the ISO's Trigger Date for each regulated solution. The ISO will also establish benchmark lead times for proposed market-based solutions.

31.2.5.6 Resolution of Deficiencies

Following initial review of the proposals, as described above, ISO staff will identify any reliability deficiencies in each of the proposed solutions. The Responsible Transmission Owner, Transmission Owner or Other Developer will discuss any identified deficiencies with the ISO staff. Other Developers and Transmission Owners that propose alternative regulated solutions shall have the option to remedy their proposals to address any deficiency within 30 days of notification by the ISO. With respect to regulated backstop solutions proposed by a Responsible Transmission Owner pursuant to Section 31.2.4.3, the Responsible Transmission Owner shall make necessary changes to its proposed backstop solution to address any reliability deficiencies identified by the ISO, and submit a revised proposal to the ISO for review within 30 days. The ISO shall review all such revised proposals to determine whether the identified deficiencies have been resolved.

31.2.5.7 ISO Report of Evaluation Results

The ISO shall present its Viability and Sufficiency Assessment to stakeholders, interested parties, and the NYDPS for comment and will indicate at that time whether any of the proposed regulated solutions found to be viable and sufficient under this Section 31.2.5 will have a Trigger Date within thirty-six months of the date of the ISO's presentation of the Viability and Sufficiency Assessment to the ESPWG.

The ISO shall report in the CRP the results of its evaluation under this Section 31.2.5: (i) whether each proposed regulated backstop solution, alternative regulated solution, and market-based solution is viable and is sufficient to satisfy the identified Reliability Need by the need date, and (ii) the Trigger Dates for the proposed regulated solutions.

31.2.6 ISO Evaluation and Selection of Proposed Regulated Transmission Solutions

31.2.6.1 Submission of Project Information for Selection of Proposed Regulated Transmission Solution

If the ISO determines that the Trigger Date of any Developer's proposed regulated solution that was found to be viable and sufficient under Section 31.2.5 will occur within thirty-six months of the date of the ISO's presentation of the Viability and Sufficiency Assessment to the ESPWG, the ISO will request that all Developers of regulated transmission solutions that the ISO determined were viable and sufficient submit to the ISO their project information, as applicable, for: (i) a proposed regulated backstop transmission solution under Section 31.2.4.4.2, or (ii) a proposed alternative regulated transmission solution under Section 31.2.4.8.2. If the ISO determines that none of the Developers' proposed regulated solutions that were found to be viable and sufficient under Section 31.2.5 have a Trigger Date that will occur within the thirty-six month period, the ISO will not request further project information, perform the evaluation, or make a selection of a more efficient or cost effective regulated solution under this Section 31.2.6 for that planning cycle.

The ISO will make its request, if necessary, for project information under this Section 31.2.6.1 sufficiently in advance of the earliest Trigger Date of the viable and sufficient regulated solutions to enable the ISO to evaluate and select the more efficient or cost effective transmission solution. Upon the ISO's request for project information, the Developers shall submit such information for their regulated transmission solution within thirty (30) days, which time period may be extended by the ISO pursuant to Section 31.1.8.7. The Developer must include with its project information a demonstration that it has an executed System Impact Study Agreement or System Reliability Impact Study Agreement, as applicable. A Developer shall submit additional project information required by the ISO within 15 days of the ISO's request. A Developer that fails to submit the required project information will not be eligible for its project to be considered in that planning cycle.

31.2.6.2 Study Deposit for Proposed Regulated Transmission Solutions

A Developer that proposes a regulated backstop transmission solution or an alternative regulated transmission solution to satisfy the identified Reliability Need shall submit to the ISO, at the same time that it provides the project information required pursuant to Section 31.2.6.1, a study deposit of $100,000, which shall be held in an interest-bearing account for which the interest earned will be associated with the Developer and shall be applied to study costs and subject to refund as described in this Section 31.2.6.2.

The ISO shall charge, and a Developer proposing a regulated backstop transmission solution or an alternative regulated transmission solution shall pay, the actual costs of the ISO's evaluation of the Developer's proposed transmission solution for purposes of the ISO's selection of the more efficient or cost effective transmission solution to satisfy a Reliability Need for cost allocation purposes, including costs associated with the ISO's use of subcontractors. The ISO will track its staff and administrative costs, including any costs associated with using subcontractors, that it incurs in performing the evaluation of a Developer's proposed transmission solution under this Section 31.2.6 and any supplemental evaluation or re-evaluation of the proposed transmission solution. If the ISO or its subcontractors perform study work for multiple proposed transmission solutions on a combined basis, the ISO will allocate the costs of the combined study work equally among the applicable Developers. The ISO shall invoice the Developer monthly for study costs incurred by the ISO in evaluating the Developer's proposed transmission solution as described above. Such invoice shall include a description and an accounting of the study costs incurred by the ISO and estimated subcontractor costs. The Developer shall pay the invoiced amount within thirty (30) calendar days of the ISO's issuance of the monthly invoice. The ISO shall continue to hold the full amount of the study deposit until settlement of the final monthly invoice; *provided, however,* if a Developer: (i) does not pay its monthly invoice within the timeframe described above, or (ii) does not pay a disputed amount into an independent escrow account as described below, the ISO may draw upon the study deposit to recover the owed amount. If the ISO must draw on the study deposit, the ISO shall provide notice to the Developer, and the Developer shall within thirty (30) calendar days of such notice make payments to the ISO to restore the full study deposit amount. If the Developer fails to make such payments, the ISO may halt its evaluation of the Developer's proposed transmission solution and may disqualify the Developer's proposed transmission solution from further consideration. After the conclusion of the ISO's evaluation of the Developer's proposed transmission solution or if the Developer: (i) withdraws its proposed transmission solution or (ii) fails to pay an invoiced amount and the ISO halts its evaluation of the proposed transmission solution, the ISO shall issue a final invoice and refund to the Developer any portion of the Developer's study deposit submitted to the ISO under this Section 31.2.6.2 and any interest actually earned on the deposited amount that together exceeds the outstanding amounts that the ISO has incurred in evaluating that Developer's proposed transmission solution. The ISO shall refund the remaining portion within sixty (60) days of the ISO's receipt of all final invoices from its subcontractors and involved Transmission Owners.

In the event of a Developer's dispute over invoiced amounts, the Developer shall: (i) timely pay any undisputed amounts to the ISO, and (ii) pay into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Developer fails to meet these two requirements, then the ISO shall not be obligated to perform or continue to perform its evaluation of the Developer's proposed transmission solution. Disputes arising under this section shall be addressed through the Dispute Resolution Procedures set forth in Section 2.16 of the ISO OATT and Section 11 of the ISO Services Tariff. Within thirty (30) Calendar Days after resolution of the dispute, the Developer will pay the ISO any amounts due with interest actually earned on such amounts.

31.2.6.3 Evaluation of System Impact of Proposed Regulated Transmission Solution

A proposed regulated transmission solution that will have a significant adverse impact on the reliability of the New York State Transmission System shall not be eligible for selection by the ISO under Section 31.2.6.5. The ISO shall evaluate the system impacts for the entire Study Period of a proposed regulated transmission solution that the ISO has determined under Section 31.2.5 is viable and sufficient. As part of this evaluation, the ISO shall give due consideration to the results of any completed System Impact Study or System Reliability Impact Study, as applicable. The ISO shall perform power flow and short circuit studies for the proposed regulated transmission solutions and additional studies, as appropriate. If the ISO identifies a significant adverse impact based on these studies, the ISO shall request that the Developer make an adjustment to its proposed regulated transmission solution to address this impact and remain eligible for selection. The Developer shall submit the adjustment within 30 days of the ISO's notification.

If the Developer modifies its proposed regulated transmission solution, the ISO shall confirm that the adjusted solution still satisfies the viability and sufficiency requirements set forth in Section 31.2.5. If the ISO determines that the proposed regulated transmission solution does not satisfy the viability and sufficiency requirements or continues to have a significantly adverse impact on the reliability of the New York State Transmission System, the ISO shall remove the proposed solution from further consideration during that planning cycle.

31.2.6.4 Evaluation of Regional Transmission Solutions to Address Local and Regional Reliability Needs More Efficiently or More Cost Effectively Than Local Transmission Solutions

The ISO will review the LTPs as they relate to BPTFs. The results of the ISO's analysis will be reported in the CRP.

31.2.6.4.1 Evaluation of Regional Transmission Solutions to Address Local Reliability Needs Identified in Local Transmission Plans More Efficiently or More Cost Effectively than Local Transmission Solutions

The ISO, using engineering judgment, will determine whether proposed regional transmission solutions on the BPTFs may more efficiently or cost effectively satisfy reliability needs identified in the LTPs. If the ISO identifies that a regional transmission solution on the BPTFs has the potential to more efficiently or cost effectively satisfy the reliability need identified in the LTPs, it will perform a sensitivity analysis to determine whether the proposed regional transmission solution on the BPTFs would satisfy the reliability needs identified in the LTPs. If the ISO determines that the proposed regional transmission solutions on the BPTFs would satisfy the reliability need, the ISO will evaluate the proposed regional transmission solution using the metrics set forth in Section 31.2.6.5.1 to determine whether it may be a more efficient or cost effective solution on the BPTFs to satisfy the reliability needs identified in the LTPs than the local solutions proposed in the LTPs.

31.2.6.4.2 Evaluation of Regional Transmission Solutions to Address Regional Reliability Needs More Efficiently or More Cost Effectively than Local Transmission Solutions

As referenced in Section 31.2.1.3, the ISO, using engineering judgment, will determine whether a regional transmission solution might more efficiently or more cost effectively satisfy an identified regional Reliability Need on the BPTFs that impacts more than one Transmission District than any local transmission solutions identified by the Transmission Owners in their LTPs in the event the LTPs specify such transmission solutions are included to address local reliability needs.

31.2.6.5 ISO Selection of More Efficient or Cost Effective Transmission Solution for Cost Allocation Purposes

A proposed regulated transmission solution – including a regulated backstop transmission solution submitted by a Responsible Transmission Owner pursuant to Section 31.2.4.3 and an alternative regulated transmission solution submitted by a Transmission Owner or Other Developer pursuant to Section 31.2.4.7 – that the ISO has determined satisfies the viability and sufficiency requirements in Section 31.2.5 and the system impact requirements in Section 31.2.6.3 shall be eligible under this Section 31.2.6.5 for selection in the CRP for the purpose of cost allocation and recovery under the ISO Tariffs. The ISO shall evaluate any eligible proposed regulated transmission solutions for the planning cycle using the metrics set forth in Section 31.2.6.5.1 below. For purposes of this evaluation, the ISO will review the information submitted by the Developer and determine whether it is reasonable and how such information should be used for purposes of the ISO evaluating each metric. In its review, the ISO will give due consideration to the status of, and any available results of, any applicable interconnection or transmission expansion studies concerning the proposed regulated transmission solution performed in accordance with Sections 3.7 or 4.5 of the ISO OATT or Attachments X or P of the ISO OATT. The ISO may engage an independent consultant to review the reasonableness and comprehensiveness of the information submitted by the Developer and may rely on the independent consultant's analysis in evaluating each metric. The ISO shall select in the CRP for cost allocation purposes the more efficient or cost effective transmission solution to satisfy a Reliability Need in the manner set forth in Section 31.2.6.5.2 below.

31.2.6.5.1 Metrics for Evaluating More Efficient or Cost Effective Regulated Transmission Solution to Satisfy Reliability Need

In determining which of the eligible proposed regulated transmission solutions is the more efficient or cost effective solution to satisfy the Reliability Need, the ISO will consider, and will consult with the NYDPS regarding, the following metrics set forth in this Section 31.2.6.5.1 and rank each proposed solution based on the quality of its satisfaction of these metrics:

31.2.6.5.1.1 The capital cost estimates for the proposed regulated transmission solutions, including the accuracy of the proposed estimates. For this evaluation, the Developer shall provide the ISO with credible capital cost estimates for its proposed solution, with itemized supporting work sheets that identify all material and labor cost assumptions, and related drawings to the extent applicable and available. The work sheets should include an estimated quantification of cost variance, providing an assumed plus/minus range around the capital cost estimate.

The estimate shall include all components that are needed to meet the Reliability Need throughout the Study Period. To the extent information is available, the Developer should itemize: material and labor cost by equipment, engineering and design work, permitting, site acquisition, procurement and construction work, and commissioning needed for the proposed solution, all in accordance with Good Utility Practice. For each of these cost categories, the Developer should specify the nature and estimated cost of all major project components and estimate the cost of the work to be done at each substation and/or on each feeder to physically and electrically connect each facility to the existing system. The work sheets should itemize to the extent applicable and available all equipment for: (i) the proposed project; (ii) interconnection facilities (including Attachment Facilities and Direct Assignment Facilities); and (iii) Network Upgrade Facilities, System Upgrade Facilities, System Deliverability Upgrades, Network Upgrades, and Distribution Upgrades.

31.2.6.5.1.2 The cost per MW ratio of the proposed regulated transmission solutions. For this evaluation, the ISO will first determine the present worth, in dollars, of the total capital cost of the proposed solution in current year dollars. The ISO will then determine the MW value of the solution by summing the Reliability Need, in MW, with the additional improvement, in MW, that the proposed solution offers beyond serving the Reliability Need. The ISO will then determine the cost per MW ratio by dividing the present worth of the total capital cost by the MW value.

31.2.6.5.1.3 The expandability of the proposed regulated transmission solution. The ISO will consider the impact of the proposed solution on future construction. The ISO will also consider the extent to which any subsequent expansion will continue to use this proposed solution within the context of system expansion.

31.2.6.5.1.4 The operability of the proposed regulated transmission solution. The ISO will consider how the proposed solution may affect additional flexibility in operating the system, such as dispatch of generation, access to operating reserves, access to ancillary services, or ability to remove transmission for maintenance. The ISO will also consider how the proposed solution may affect the cost of operating the system, such as how it may affect the need for operating generation out of merit for reliability needs, reducing the need to cycle generation, or providing more balance in the system to respond to system conditions that are more severe than design conditions.

31.2.6.5.1.5 The performance of the proposed regulated transmission solution. The ISO will consider how the proposed project may affect the utilization of the system (*e.g.* interface flows, percent loading of facilities).

31.2.6.5.1.6 The extent to which the Developer of a proposed regulated transmission solution has the property rights, or ability to obtain the property rights, required to implement the solution. The ISO will consider whether the Developer: (i) already possesses the rights of way necessary to implement the solution; (ii) has completed a transmission routing study, which (a) identifies a specific routing plan with alternatives, (b) includes a schedule indicating the timing for obtaining siting and permitting, and (c) provides specific attention to sensitive areas (e.g., wetlands, river crossings, protected areas, and schools); or (iii) has specified a plan or approach for determining routing and acquiring property rights.

31.2.6.5.1.7 The potential issues associated with delay in constructing the proposed regulated transmission solution consistent with the major milestone schedule and the schedule for obtaining any permits and other certifications as required to timely meet the need.

31.2.6.5.2 ISO Selection of More Efficient or Cost Effective Regulated Transmission Solution to Satisfy Reliability Need

The ISO shall select under this Section 31.2.6.5.2 the proposed regulated transmission solution, if any, that is the more efficient or cost effective transmission solution proposed in the planning cycle to satisfy the identified Reliability Need. The ISO shall report the selected regulated transmission solution in the CRP. The selected regulated transmission solution reported in the CRP shall be eligible to be triggered by the ISO to satisfy the identified Reliability Need pursuant to Section 31.2.8 at any point within thirty-six months of the date of the ISO's presentation of the Viability and Sufficiency Assessment to the ESPWG. An Other Developer or Transmission Owner of an alternative regulated transmission project shall not be eligible for cost allocation and cost recovery under the ISO OATT for its project unless its project is selected pursuant to this Section 31.2.6.5.2. Once such project is selected, the Other Developer or Transmission Owner shall be eligible for cost allocation and cost recovery under the ISO OATT for its project. Within thirty (30) days of the ISO's selection of an alternative regulated transmission solution, the Other Developer or Transmission Owner shall submit to the ISO for the ISO's approval a proposed schedule and scope of work that describe the preparation work, if any, that the Developer must perform prior to the Trigger Date of the project, including a good faith estimate of the costs of such work. Costs will be recovered when the project enters into service, is halted, or as otherwise determined by the Commission in accordance with the cost recovery requirements set forth in Section 31.5.6 of this Attachment Y and Rate Schedule 10 of the ISO OATT. Actual project cost recovery, including any issues related to cost recovery and project cost overruns, will be submitted to and decided by the Commission.

31.2.7 Comprehensive Reliability Plan

Following the ISO's evaluation of the proposed market-based and regulated solutions to Reliability Need(s), the ISO will prepare a draft CRP that sets forth the ISO's findings regarding the viability and sufficiency of solutions, the trigger dates of regulated solutions, and any recommendations that implementation of regulated solutions (which may be a Gap Solution) is necessary to ensure system reliability. The draft CRP will reflect any input from the NYDPS. If the CRP cannot be completed in the two-year planning cycle, the ISO will notify stakeholders and provide an estimated completion date and an explanation of the reasons the additional time is required.

The ISO will include in the draft CRP the list of Developers that qualify pursuant to Section 31.2.4.1 and will identify the proposed solutions that it has determined under Section 31.2.5 are viable and sufficient to satisfy the identified Reliability Need(s) by the need date. The ISO will identify in the CRP the regulated backstop solution that the ISO has determined will meet the Reliability Need by the need date and the Responsible Transmission Owner. If the ISO determines at the time of the issuance of the CRP that sufficient market-based solutions will not be available in time to meet a Reliability Need, and finds that it is necessary to take action to ensure reliability, it will state in the CRP that the development of regulated solutions (regulated backstop or alternative regulated solution) is necessary. The draft CRP will also include the results of the ISO's analysis of the LTPs consistent with Section 31.2.6.4.

The draft CRP shall indicate whether the ISO has determined that the Trigger Date to any proposed regulated solution will occur within thirty-six months of the date of ISO's presentation of the Viability and Sufficiency Assessment to the ESPWG. If the Trigger Date of any proposed regulated solution will occur within the thirty-six month period and the ISO makes a selection of the more efficient or cost effective transmission solution under Section 31.2.6.5.2, the draft CRP shall include the regulated transmission solution selected for cost allocation purposes pursuant to Section 31.2.6.5.2 as the more efficient or cost effective transmission solution to satisfy the Reliability Need(s) and shall indicate whether that transmission solution should be triggered. The draft CRP shall also indicate the date by which a solution must be in-service to satisfy the Reliability Need.

If: (i) none of the proposed regulated solutions has a Trigger Date within the thirty-six month period, or (ii) the Trigger Date of any proposed regulated solution will occur within the thirty-six month period but the ISO determines in its discretion that it is not necessary at that time to select a more efficient or cost effective transmission solution under Section 31.2.6.5.2 prior to the completion of the CRP, the draft CRP will not select a regulated transmission solution. If: (i) the Trigger Date of any proposed regulated solution will occur within the thirty-six month period, and (ii) the ISO selects a more efficient or cost effective solution subsequent to the completion of the CRP but prior to the completion of that thirty-six month period, the ISO shall issue an updated CRP report pursuant to Section 31.2.7.3 that indicates the regulated transmission solution selected for cost allocation purposes pursuant to Section 31.2.6.5.2 as the more efficient or cost effective transmission solution to satisfy the Reliability Need(s) whether that transmission solution should be triggered, and the date by which a solution must be in-service to satisfy the Reliability Need.

The draft CRP shall include a comparison of a proposed regional solution to an identified Reliability Need to an Interregional Transmission Project identified and evaluated under the “Analysis and Consideration of Interregional Transmission Projects” section of the Interregional Planning Protocol, if any. An Interregional Transmission Project proposed in the ISO’s reliability planning process may be selected as a market based response, regulated backstop solution, or an alternative regulated solution under the provisions of the ISO's reliability planning process.

31.2.7.1 Collaborative Governance Process

The ISO staff shall submit the draft CRP to the TPAS and ESPWG for review and comment. The ISO shall make available to any interested party sufficient information to replicate the results of the draft CRP. The information made available will be electronically masked and made available pursuant to a process that the ISO reasonably determines is necessary to prevent the disclosure of any Confidential Information or Critical Energy Infrastructure Information contained in the information made available. Following completion of the TPAS and ESPWG review, the draft CRP reflecting the revisions resulting from the TPAS and ESPWG review shall be forwarded to the Operating Committee for a discussion and action. The ISO shall notify the Business Issues Committee of the date of the Operating Committee meeting at which the draft CRP is to be presented. Following the Operating Committee vote, the draft CRP will be transmitted to the Management Committee for a discussion and action.

31.2.7.2 Board Review, Consideration, and Approval of CRP

Following the Management Committee vote, the draft CRP, with working group, Operating Committee, and Management Committee input, will be forwarded to the ISO Board for review and action. Concurrently, the draft CRP will also be provided to the Market Monitoring Unit for its review and consideration of whether market rule changes are necessary to address an identified failure, if any, in one of the ISO's competitive markets. The Board may approve the draft CRP as submitted or propose modifications on its own motion, including the recommendations regarding the selection of transmission projects for cost allocation and cost recovery under the ISO Tariffs if such selection will occur during that planning cycle. If any changes are proposed by the Board, the revised CRP shall be returned to the Management Committee for comment. The Board shall not make a final determination on the draft CRP until it has reviewed the Management Committee comments. Upon final approval by the Board, the ISO shall issue the CRP to the marketplace by posting the CRP on its website. The ISO will provide the CRP to the appropriate regulatory agency(ies) for consideration and appropriate action.

The responsibilities of the Market Monitoring Unit that are addressed in the above section of Attachment Y to the ISO OATT are also addressed in Section 30.4.6.8.3 of the Market Monitoring Plan, Attachment O to the ISO Services Tariff.

31.2.7.3 Updated CRP Report

If, pursuant to Section 31.2.7, the ISO identifies a proposed regulated transmission solution as the more efficient or cost effective transmission solution following the completion of the CRP, the ISO will prepare a draft updated CRP report that indicates the regulated transmission solution recommended for selection for cost allocation purposes pursuant to Section 31.2.6.5.2 as the more efficient or cost effective transmission solution to satisfy the Reliability Need(s), whether that transmission solution should be triggered at that time, and the date by which a solution must be in-service to satisfy the Reliability Need. The draft updated CRP report shall be reviewed in accordance with the stakeholder process set forth in Section 31.2.7.1 and will be then forwarded to the ISO Board for its review and action pursuant to Section 31.2.7.2.

31.2.7.4 Reliability Disputes

Notwithstanding any provision to the contrary in this Attachment, the ISO OATT, or the ISO Services Tariff, in the event that a Market Participant or other interested party raises a dispute solely within the NYPSC's jurisdiction concerning ISO's final determination in the CRP that a proposed solution will or will not meet a Reliability Need, a Market Participant or other interested party seeking further review shall refer such dispute to the NYPSC for resolution, as provided for in the ISO Procedures. The NYPSC's final determination of such disputes shall be binding, subject only to judicial review in the courts of the State of New York pursuant to Article 78 of the New York Civil Practice Law and Rules.

31.2.7.5 Posting of Approved Solutions

The ISO shall post on its website a list of all Developers that have undertaken a commitment to the ISO to build a project (which may be a regulated backstop solution, market-based response, alternative regulated response or gap solution) that is necessary to ensure system reliability, as identified in the CRP and approved by the appropriate governmental agency(ies) and/or authority(ies).