1.1 Definitions - A

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 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.

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

Ancillary Services: 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 by an Eligible Customer for Transmission Service pursuant to the provisions of this Tariff.

Automatic Generation Control ("AGC"): The automatic regulation of the power output of electric generating facilities 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, 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 Reserves: For purposes of determining the Real-Time Locational Based Marginal Price in any Real-Time Dispatch interval: the capability of all Suppliers that submit Energy Bids to provide Spinning Reserves, Non-Synchronized 10-Minute Reserves, and 30-Minute Reserves in that interval, and in the relevant location, and the quantity of recallable external ICAP energy sales in that interval.

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. ATC is defined as the Total Transfer Capability, less Transmission Reliability Margin, less the sum of existing transmission commitments, (which includes retail customer service) less the Capacity Benefit Margin. The amount reserved to support existing transmission commitments is defined in the Existing Transmission Agreements and Existing Transmission Capacity for Native Load in Attachment L.

1.9 Definitions - I

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.

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 Transmission Owners 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) a Day-Ahead Demand Reduction Provider's Demand Reduction shall be included as Injection Billing Units. For purposes of recovering the ISO annual budgeted costs pursuant to Rate Schedule 1 of this ISO OATT, Injection Billing Units shall include the absolute value of negative injections by pump storage facilities.

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.

Intermittent Power Resource: Capacity resources that depend upon wind, or solar energy or landfill gas for their fuel and that such dependence precludes accurate prediction of the facility's real-time output. 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.

Interruption: A reduction in non-Firm Transmission service due to economic reasons pursuant to Section 3.2.7.

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.

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

ISO Market Power Monitoring Program: The monitoring program approved by the Commission and administered by the ISO 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 and the ISO/TO Agreement.

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

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

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.

Scheduled Energy Injections: Energy injections ~~which~~ that are scheduled on a real-time basis by RT~~C~~D.

Scheduled Energy Withdrawals: Energy withdrawals that are scheduled on a real-time basis by RTD.

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 following transmission facilities are Scheduled Lines: the Cross-Sound Scheduled Line, the Neptune Scheduled Line, the Dennison Scheduled Line, the Northport-Norwalk Scheduled Line, and the Linden VFT Scheduled Line.

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 is self-committed and opts not to be Dispatchable over any portion of its operating range.

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

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

Service Agreement: The 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 Bid Price 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.

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 or a Demand Side Resource from a level of no Demand Reduction to its specified minimum level of Demand Reduction.

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

1.23 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.

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 26.8.2 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.

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.

2.3 Ancillary Services

Ancillary Services are needed with Transmission Service to maintain reliability within and among the Control Areas affected by the Transmission Service. The ISO is required to provide, and the Transmission Customer is required to purchase, the following Ancillary Services: (i) Scheduling, System Control and Dispatch, (ii) Voltage Support Service, (iii) Energy Imbalance and (iv) Black Start Service.

The ISO is required to offer to provide the following Ancillary Services only to the Transmission Customers serving Load within the NYCA: (i) Regulation and Frequency Response, and (ii) Operating Reserves. The Transmission Customer serving Load within the NYCA is required to acquire these Ancillary Services, whether from the ISO, a third party, or by Self-Supply pursuant to Schedules 3 and 5. The Transmission Customer may not decline the ISO's offer of Ancillary Services unless it demonstrates that it has acquired the Ancillary Services from another source. The Transmission Customer must list in its Application which Ancillary Services it will purchase from the ISO.

The ISO shall specify the rate treatment and all related terms and conditions in the event of an unauthorized use of Ancillary Services by the Transmission Customer.

The specific Ancillary Services, prices and/or compensation methods are described on the schedules that are attached to and made a part of this Tariff. Sections 2.3.1 through 2.3.6 below list the six Ancillary Services.

2.3.1 Scheduling, System Control and Dispatch Service:

The costs for Scheduling, System Control, and Dispatch Service are included among those costs recovered through Schedule 1.

2.3.2 Voltage Support Service:

The rates and/or methodology are described in Schedule 2.

2.3.3 Regulation and Frequency Response Service:

The rates and/or methodology are described in Schedule 3.

2.3.4 Energy Imbalance Service:

The rates and/or methodology are described in Schedule 4.

2.3.5 Operating Reserve Service:

The rates and/or methodology are described in Schedule 5.

2.3.6 ISO Black Start Capability:

The rates and/or methodology are described in Schedule 6.

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 on a monthly basis to recover the ISO's annual budgeted costs as set forth in Article 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 as set forth in Article 6.1.3 of this Rate Schedule 1. The ISO shall also bill each Transmission Customer on a monthly basis 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 Article 6.1.4;

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

(iii) non-ISO facilities payment charges as set forth in Article 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 Article 6.1.7;

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

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

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

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

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

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

(xi) payments to allocate financial penalties collected by the ISO as set forth in Article 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 credit the revenue collected through Section 6.1.2.4 of this Rate Schedule 1 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 Article 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 on a monthly basis as calculated according to the following formula.

$$\text{ISO Annual Budget Charge}_{c,M} = \begin{matrix} \left(InjectionUnits_{c,M} \times \left(.2 \times \frac{ISOCosts_{Annual}}{TotalEstWithdrawalUnits_{Annual}} \right) \right) + \\ \left(WithdrawalUnits_{c,M} \times \left(.8 \times \frac{ISOCosts_{Annual}}{TotalEstWithdrawalUnits_{Annual}} \right) \right) \end{matrix}$$

Where:

c = Transmission Customer.

M = The relevant month.

ISO Annual Budget Charge$_{c,M}$ = The amount, in \$, of the ISO annual budgeted costs for which Transmission Customer c is responsible for month M.

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

InjectionUnits$_{c,M}$ = The Injection Billing Units, in MWh, for Transmission Customer c in month M.

WithdrawalUnits$_{c,M}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer c in month M.

$TotalEstWithdrawalUnits_{Annual}$ = 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.

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

The current 80%/20% 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, 2011 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 80%/20% 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 80%/20% cost allocation on a going forward basis:

(i) A vote of the Management Committee will be taken in the third calendar quarter of 2010 on whether a new study should be conducted during late-2010 and 2011 to allow modification of the 80%/20% cost allocation, if warranted by the results of the study, to be implemented by January 1, 2012. 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 80%/20% cost allocation between Withdrawal Billing Units and Injection Billing Units shall be extended through at least December 31, 2012. In the third calendar quarter of 2011, a vote will be taken on whether a new study should be conducted during late-2011 and 2012 to allow modification of the percentage allocation, if warranted by the results of the study, to be implemented by January 1, 2013. 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 2011 discussed in (ii) above determines that a study should not be conducted, the current 80%/20% 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 2011 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 2011 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 on a monthly basis as calculated according to the following formula.

$$VTCharge_{c,M} = VTRate \times VTCleared_{c,M}$$

Where:

c = Transmission Customer.

M = The relevant month.

$VTCharge_{c,M}$ = The amount, in $, for which Transmission Customer c is responsible for month M.

VTRate = For calendar year 2010, the applicable rate shall be $0.065 per cleared MWh of Virtual Transactions, based on a $2.0 million projected 2010 annual revenue requirement. For calendar years following 2010, 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.

$VTCleared_{c,M}$ = The total cleared Virtual Transactions, in MWh, for Transmission Customer c in month M.

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 on a monthly basis as calculated according to the following formula.

$$\text{TCCCharge}_{c,M} = \text{TCCRate} \times \text{TCCSettled}_{c,M}$$

Where:

c = Transmission Customer.

M = The relevant month.

$\text{TCCCharge}_{c,M}$ = The amount, in $, for which Transmission Customer c is responsible for month M.

TCCRate = For calendar year 2010, the applicable rate shall be $0.020 per settled MWh of Transmission Congestion Contracts, based on a $6.7 million projected 2010 annual revenue requirement. For calendar years following 2010, 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.

$\text{TCCSettled}_{c,M}$ = The total settled Transmission Congestion Contracts, excluding Transmission Congestion Contracts created prior to January 1, 2010, in MWh, for Transmission Customer c in month M.

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 on a monthly basis as calculated according to the following formula.

$$\text{SCR and EDR Charge}_{c,M} = \text{DRInjections}_{c,M} \times \left(.2 \times \frac{\text{ISOCosts}_{\text{Annual}}}{\text{TotalEstWithdrawalUnits}_{\text{Annual}}} \right)$$

Where:

c = Transmission Customer.

M = The relevant month.

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

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

$ISOCosts_{Annual}$ = 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.

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 2010, 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 2010, 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

The ISO shall distribute on a monthly basis the revenue collected pursuant to Section 6.1.2.4 of this Rate Schedule 1 to each Transmission Customer that participates in physical market activity as calculated according to the following formula.

$$\text{ISO Annual Budget Credit}_{c,M} = \begin{pmatrix} \left(\text{NonPhysicalActivityRevenue}_M \times \left(.2 \times \frac{\text{InjectionUnits}_{c,M}}{\text{TotalInjectionUnits}_M} \right) \right) + \\ \left(\text{NonPhysicalActivityRevenue}_M \times \left(.8 \times \frac{\text{WithdrawalUnits}_{c,M}}{\text{TotalWithdrawalUnits}_M} \right) \right) \end{pmatrix}$$

Where:

c = Transmission Customer.

M = The relevant month.

ISO Annual Budget Credit$_{c,M}$ = The amount, in $, that Transmission Customer c will receive for month M.

NonPhysicalActivityRevenue$_M$ = The sum, in $, of the revenue collected by the ISO for month M through the charges to Transmission Customers for non-physical market activity, the Special Cases Resource program, and the Emergency Demand Response program as calculated in Section 6.1.2.4 of this Rate Schedule 1.

InjectionUnits$_{c,M}$ = The Injection Billing Units, in MWh, for Transmission Customer c in month M.

WithdrawalUnits$_{c,M}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer c in month M.

TotalInjectionUnits$_M$ = The sum, in MWh, of Injection Billing Units for all Transmission Customers in month M.

TotalWithdrawalUnits$_M$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in month M.

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.

$$\text{NERC\&NPCC Charge}_{c,Q} = \text{NERC\&NPCCCosts}_{Q} \times \frac{\text{TUWithdrawalUnits}_{c,M}}{\text{TUTotalWithdrawalUnits}_{M}}$$

Where:

c = Transmission Customer.

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

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

$\text{NERC\&NPCCCosts}_{Q}$ = 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.

$\text{TUWithdrawalUnits}_{c,M}$ = 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.

$\text{TUTotalWithdrawalUnits}_{M}$ = 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 7.4.2.1.2 and 7.4.2.1.3 of the ISO Services Tariff and Sections 2.7.4.3.1(ii) and 2.7.4.3.1(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 collection of costs related to 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 6.1.6.1 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 Branchburg-Ramapo Interconnection between the ISO and PJM Interconnection, LLC, 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 Non-ISO Facilities Payment Charge

6.1.6.1.1 Transmission Customer Charge Based on Withdrawal Billing Units Not Used to Supply Station Power Under Part 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 month. 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 month.

$$\text{Non-ISO Facilities Payment Charge}_{c,h} = \frac{\text{NonISOFacilitiesCosts}_M}{N} \times \frac{\text{WithdrawalUnits}_{c,h}}{\text{TotalWithdrawalUnits}_h}$$

Where:

c = Transmission Customer.

M = The relevant month.

h = A given hour in month M.

N = Total number of hours h in month M.

Non-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 one-half 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.

$TotalWithdrawalUnits_h$ = 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.

6.1.6.1.2 Transmission Customer Charge Based on Withdrawal Billing Units to Supply Station Power Under Part 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 month. 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 month.

Non-ISO Facilities Payment $Charge_{c,d}$ =

$$\frac{NonISOFacilitiesCosts_M}{N} \times \frac{StationPower_{c,d}}{TotalWithdrawalUnits_d}$$

Where:

d = A given day 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 6.1.6.1.1 of this Rate Schedule 1 above, except that the variables in this Section 6.1.6.1.2 shall be determined for day d.

6.1.6.1.3 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 6.1.6.1.2 of this Rate Schedule 1 for each month. 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 month.

Non-ISO Facilities Payment Credit$_{c,d}$ =

$$NonISOFacPayCharge_{d} \times \frac{WithdrawalUnits_{c,d}}{TotalWithdrawalUnits_{d}}$$

Where:

d = A given day in the relevant month.

Non-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 6.1.6.1.2 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 6.1.6.1.1 of this Rate Schedule 1 above, except that the variables in this Section 6.1.6.1.3 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 month. 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 month. 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$_{c,d}$ =

$$\text{LRRPayment}_d \times \frac{\text{TDWithdrawalUnits}_{c,d}}{\text{TDTotalWithdrawalUnits}_d}$$

Where:

c = Transmission Customer.

d = A given day in the relevant month.

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 Part 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 month. The monthly payment or charge 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 month, 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 month. If the result of this determination is positive, the ISO shall pay the Transmission Customer a residual costs payment for the relevant month. If the result of this determination is negative, the ISO shall charge the Transmission Customer a residual costs charge for the relevant month.

Residual Costs Payment/Charge$_{c,h}$ =

$$\left(\text{CustomerPayments}_h - \text{ISOPayments}_h\right) \times \frac{\text{WithdrawalUnits}_{c,h}}{\text{TotalWithdrawalUnits}_h}$$

Where:

c = Transmission Customer.

h = A given hour in the relevant month.

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.

$TotalWithdrawalUnits_h$ = 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.

$CustomerPayments_h$ = 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.

$ISOPayments_h$ = 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 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 Part 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 month. The monthly payment or charge 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 month, 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 month. If the result of this determination is positive, the ISO shall pay the Transmission Customer a residual costs payment for the relevant month. If the result of this determination is negative, the ISO shall charge the Transmission Customer a residual costs charge for the relevant month.

Residual Costs Payment/Charge$_{c,d}$ =

$$\frac{\left(\text{CustomerPayments}_d \text{-ISOPayments}_d\right)}{\text{TotalWithdrawalUnits}_d} \times \text{StationPower}_{c,d}$$

Where:

d = A given day in the relevant month.

$StationPower_{c,d}$ = 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 month. 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 month. If the summed amount is positive for the month, the ISO shall pay the Transmission Customer the adjustment amount. If the summed amount is negative for the month, the ISO shall charge the Transmission Customer the adjustment amount.

Residual Costs $Adjustment_{c,d}$ =

$$\text{ResidCharge/PaymentCosts}_d \times \frac{\text{WithdrawalUnits}_{c,d}}{\text{TotalWithdrawalUnits}_d}$$

Where:

d = A given day in the relevant month.

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 month. 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 month 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.

$Local\ Reliability\ SCR\ and\ CSP\ Charge_{c,h}$ =

$$\text{LocalReliabilityCosts}_h \times \frac{\text{SZWithdrawalUnits}_{c,h}}{\text{SZTotalWithdrawalUnits}_h}$$

Where:

c = Transmission Customer.

h = A given hour in the relevant month.

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 that serves Load in the NYCA 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.

NYCA Reliability SCR and CSP Charge$_{c,h}$ =

$$\text{NYCAReliabilityCosts}_h \times \frac{\text{WithdrawalUnits}_{c,h}}{\text{TotalWithdrawalUnits}_h}$$

Where:

c = Transmission Customer.

h = A given hour in the relevant month.

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

$\text{NYCAReliabilityCosts}_{h}$ = 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.

$\text{WithdrawalUnits}_{c,h}$ = 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.

$\text{TotalWithdrawalUnits}_{h}$ = 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.

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 month. This monthly charge 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 month 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 Part 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.

$$\text{Local Reliability DAMAP Charge}_{c,h} = \text{DAMAPCosts}_h \times \frac{\text{SZWithdrawalUnits}_{c,h}}{\text{SZTotalWithdrawalUnits}_h}$$

Where:

c = Transmission Customer.

h = A given hour in the relevant month.

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 Part 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.

$$\text{Local Reliability DAMAP Charge}_{c,d} = \frac{\text{DAMAPCosts}_d}{\text{SZTotalWithdrawalUnits}_d} \times \text{SZStationPower}_{c,d}$$

Where:

d = A given day in the relevant month.

$SZStationPower_{c,d}$ = 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 month.

Local Reliability DAMAP $Credit_{c,d}$ =

$$LocRelDAMAPCharge_{d} \times \frac{SZWithdrawalUnits_{c,d}}{SZTotalWithdrawalUnits_{d}}$$

Where:

d = A given day in the relevant month.

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 Part 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.

$$\text{Remaining DAMAP Charge}_{c,h} = \text{RemainingDAMAPCosts}_h \times \frac{\text{WithdrawalUnits}_{c,h}}{\text{TotalWithdrawalUnits}_h}$$

Where:

c = Transmission Customer.

h = A given hour in the relevant month.

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.

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.

6.1.10.2.2 Transmission Customer Charge Based on Withdrawal Billing Units to Supply Station Power Under Part 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.

$$\text{Remaining DAMAP Charge}_{c,d} = \frac{\text{RemainingDAMAPCosts}_d}{\text{TotalWithdrawalUnits}_d} \times \text{StationPower}_{c,d}$$

Where:

d = A given day in the relevant month.

$\text{StationPower}_{c,d}$ = 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 month.

$$\text{Remaining DAMAP Credit}_{c,d} = \text{RemainingDAMAPCharge}_d \times \frac{\text{WithdrawalUnits}_{c,d}}{\text{TotalWithdrawalUnits}_d}$$

Where:

d = A given day in the relevant month.

$\text{Remaining DAMAP Credit}_{c,d}$ = 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 Part 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 monthly charge to recover the costs of all Import Curtailment Guarantee Payments paid to Import Suppliers for each month. This monthly charge 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 month.

$$\text{Import Curtailment Guarantee Charge}_{c,h} = \text{ImportCurtGuarCosts}_h \times \frac{\text{WithdrawalUnits}_{c,h}}{\text{TotalWithdrawalUnits}_h}$$

Where:

c = Transmission Customer.

h = A given hour in the relevant month.

$\text{Import Curtailment Guarantee Charge}_{c,h}$ = 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.

$TotalWithdrawalUnits_h$ = 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.

6.1.11.2 Transmission Customer Charge Based on Withdrawal Billing Units to Supply Station Power Under Part 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 monthly charge to recover the costs of all Import Curtailment Guarantee Payments paid to Import Suppliers for each month. This charge 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 month.

$$\text{Import Curtailment Guarantee Charge}_{c,d} = \frac{\text{ImportCurtGuarCosts}_d}{\text{TotalWithdrawalUnits}_d} \times \text{StationPower}_{c,d}$$

Where:

d = A given day in the relevant month.

$StationPower_{c,d}$ = 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 month. 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 month.

$$\text{Import Curtailment Guarantee Credit}_{c,d} = \text{ImpCurtGuarCharge}_d \times \frac{\text{WithdrawalUnits}_{c,d}}{\text{TotalWithdrawalUnits}_d}$$

Where:

d = A given day in the relevant month.

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 and Demand Reduction Incentive Payment Costs

The ISO shall charge, and each Transmission Customer shall pay, a charge for the recovery of BPCG and Demand Reduction Incentive Payment costs for each month. This monthly charge shall be equal to the sum of the charges and credits for the Transmission Customer, as calculated in Sections 6.1.12.1 through 6.1.12.6 of this Rate Schedule 1, for each day and for each Subzone, where applicable.

6.1.12.1 Costs of Demand Reduction BPCGs and Demand Reduction Incentive Payments

After accounting for imbalance charges paid by Demand Reduction Providers, the ISO shall recover the costs associated with Demand Reduction Bid Production Cost guarantee payments and Demand Reduction Incentive Payments from Transmission Customers pursuant to the methodology established in Attachment R of this ISO OATT.

6.1.12.2 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 6.1.12.6 of this Rate Schedule 1.

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

Pursuant to this Section 6.1.12.3, 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.

6.1.12.3.1 Transmission Customer Charge Based on Withdrawal Billing Units Not Used to Supply Station Power Under Part 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.

$$\text{Local Reliability BPCG Charge}_{c,d} = \text{BPCGCosts}_{d} \times \frac{\text{SZWithdrawalUnits}_{c,d}}{\text{SZTotalWithdrawalUnits}_{d}}$$

Where:

c = Transmission Customer.

d = A given day in the relevant month.

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.

6.1.12.3.2 Transmission Customer Charge Based on Withdrawal Billing Units to Supply Station Power Under Part 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.

$$\text{Local Reliability BPCG Charge}_{c,d} = \frac{\text{BPCGCosts}_d}{\text{SZTotalWithdrawalUnits}_d} \times \text{SZStationPower}_{c,d}$$

Where:

$\text{SZStationPower}_{c,d}$ = 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,

6.1.12.3.3 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 6.1.12.3.2 of this Rate Schedule 1. This credit shall be calculated according to the following formula for each day in the relevant month.

$$\text{Local Reliability BPCG Credit}_{c,d} = \text{LocRelBPCGCharge}_d \times \frac{\text{SZWithdrawalUnits}_{c,d}}{\text{SZTotalWithdrawalUnits}_d}$$

Where:

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

$\text{LocRelBPCGCharge}_d$ = The sum of charges, in $, for all Transmission Customers in the relevant Subzone as calculated in Section 6.1.12.3.2 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 6.1.12.3.1 above.

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

Pursuant to this Section 6.1.12.4, 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.

$$\text{Local Reliability SCR BPCG Charge}_{c,d} = \text{BPCGCosts}_d \times \frac{\text{SZWithdrawalUnits}_{c,d}}{\text{SZTotalWithdrawalUnits}_d}$$

Where:

c = Transmission Customer.

d = A given day in the relevant month.

Local Reliability SCR BPCG $\text{Charge}_{c,d}$ = 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.

$\text{SZWithdrawalUnits}_{c,d}$ = 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.

$\text{SZTotalWithdrawalUnits}_d$ = 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.

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

Pursuant to this Section 6.1.12.5, 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 that serves Load in the NYCA 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.

$$\text{NYCA Reliability SCR BPCG Charge}_{c,d} = \text{BPCGCosts}_d \times \frac{\text{WithdrawalUnits}_{c,d}}{\text{TotalWithdrawalUnits}_d}$$

Where:

c = Transmission Customer.

d = A given day in the relevant month.

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 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 to supply Station Power as third-party providers.

6.1.12.6 Costs of All Remaining BPCGs

Pursuant to this Section 6.1.12.6, 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, 6.1.12.4, and 6.1.12.5 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.

6.1.12.6.1 Transmission Customer Charge Based on Withdrawal Billing Units Not Used to Supply Station Power Under Part 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.

$$\text{Remaining BPCG Charge}_{c,d} = \text{RemainingBPCGCosts}_d \times \frac{\text{WithdrawalUnits}_{c,d}}{\text{TotalWithdrawalUnits}_d}$$

Where:

c = Transmission Customer.

d = A given day in the relevant month.

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, 6.1.12.4, and 6.1.12.5 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.

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.

6.1.12.6.2 Transmission Customer Charge Based on Withdrawal Billing Units to Supply Station Power Under Part 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.

$$\text{Remaining BPCG Charge}_{c,d} = \frac{\text{RemainingBPCGCosts}_d}{\text{TotalWithdrawalUnits}_d} \times \text{StationPower}_{c,d}$$

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 6.1.12.6.1 of this Rate Schedule 1 above.

6.1.12.6.3 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 6.1.12.6.2 of this Rate Schedule 1. This credit shall be calculated according to the following formula for each day in the relevant month.

$$\text{Remaining BPCG Credit}_{c,d} = \text{RemainingBPCGCharge}_{d} \times \frac{\text{WithdrawalUnits}_{c,d}}{\text{TotalWithdrawalUnits}_{d}}$$

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 6.1.12.6.2 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 6.1.12.6.1 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 month as calculated according to the following formula.

Dispute Resolution Payment/ Charge$_{c,M}$ =

$$\text{DisputeResolutionCosts}_{M} \times \frac{\text{WithdrawalUnits}_{c,M}}{\text{TotalWithdrawalUnits}_{M}}$$

Where:

c = Transmission Customer.

M = The relevant month.

Dispute Resolution Payment/Charge$_{c,M}$ = The amount, in $, for month M 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$_{M}$ = The amount, in $, for month M 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$_{c,M}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer c in month M.

TotalWithdrawalUnits$_{M}$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in month M.

6.1.14 Credit for Financial Penalties

The ISO shall distribute to each Transmission Customer on a monthly basis 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.

$$\text{Financial Penalties Credit}_{c,M} = \text{PenaltyRevenue}_M \times \frac{\text{WithdrawalUnits}_{c,M}}{\text{TotalWithdrawalUnits}_M}$$

Where:

c = Transmission Customer.

M = A given day in the relevant month.

Financial Penalties Credit$_{c,M}$ = The amount, in \$, that Transmission Customer c will receive for month M.

PenaltyRevenue$_M$ = The sum, in \$, of revenue that the ISO has collected for month M from a Transmission Customer for one of the financial penalties indicated in this Article 6.1.14 of this Rate Schedule 1.

WithdrawalUnits$_{c,M}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer c for month M.

TotalWithdrawalUnits$_M$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers for month M.

6.4 Schedule 4 - Energy Imbalance Service

Energy Imbalance Service is provided when (1) a difference occurs between the scheduled and the actual delivery of Energy to a Load located within the NYCA over a single hour, or (2) a difference occurs between the scheduled and actual delivery of Energy from a POI within the NYCA to a neighboring control area in a single hour. 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 located in the NYCA. The Transmission Customer must purchase this service from the ISO. The charges for Energy Imbalance Service are set forth below.

6.4.1 Energy Imbalance Service Charges

For each Transmission Customer that has executed a Service Agreement under the ISO Services Tariff, Energy Imbalance Service is considered to be supplied by the Real-Time Market and will be charged at the Real-Time LBMP price determined pursuant to Attachment J.

For each Transmission Customer that is not a Customer under the ISO Services Tariff and is receiving service under Section 3 or 4 of this Tariff, the ISO shall establish a deviation band of +/- 1.5 percent (with a minimum of 2 MW) of the scheduled transaction to be applied hourly to any Energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s). Parties should attempt to eliminate Energy imbalances within the limits of the deviation band within thirty (30) days or within such other reasonable period of time as may be established by the ISO that is generally accepted in the region and consistently adhered to by the ISO. If an Energy imbalance is not corrected within thirty (30) days or such other reasonable period of time as may be established by the ISO that is generally accepted in the region and consistently adhered to by the ISO, the Transmission Customer will compensate the ISO for such service, subject to the charges set forth below. Also, Energy imbalances outside the deviation band will be subject to charges set forth below.

For hours when the Transmission Customer's Actual Energy Withdrawals are greater than that customer's scheduled Energy delivery and applicable tolerance band, the Transmission Customer shall pay to the ISO an amount equal to the greater of 150% of the Real-Time LBMP price at the Point of Delivery or $100 per MWh. In the event that the Transmission Customer's Actual Energy delivery exceeds that customer's Actual Energy Withdrawals, the Transmission Customer shall not receive payment for such Energy.

Transmission Customers with imbalances may also be subject to charges for Regulation and Frequency Response, as described in Rate Schedule 3.

Energy imbalances resulting from inadvertent interchange between Control Areas will continue to be addressed by the procedures that Control Area operators currently use to address such imbalances. 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

For Energy imbalances resulting from inadvertent interchange between Control Areas, the ISO shall: (i) accurately account for inadvertent Energy interchange, through daily schedule verification and the use of reliable metering equipment; (ii) minimize unintentional inadvertent accumulation in accordance with NERC and NPCC policies; and (iii) minimize accumulated inadvertent Energy balances in accordance with NERC and NPCC policies.

The ISO shall reduce accumulated inadvertent Energy balances with other Control Areas by one or both of the following methods: (i) scheduling interchange payback with another

Control Area as an interchange schedule between Control Areas; and (ii) unilaterally offsetting the tie-line interchange schedule when such action will assist in correcting an existing time error.

Inadvertent interchange accumulated during On-Peak hours shall be paid back during On-Peak hours. Inadvertent interchange accumulated during Off-Peak hours shall be paid back during Off-Peak hours. In either case, payback is made with Energy "in-kind."

6.4.3 Monthly Meter Reading Adjustments

6.4.3.1 Facilities Internal to the NYCA

The ISO shall develop rules and procedures to implement adjustments to meter readings to reflect the differences between the integrated instantaneous metering data utilized by the ISO for SCD and actual data for internal facilities as recorded by billing metering.

6.4.3.2 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 to be established by the ISO in accordance with NERC and other established reliability criteria.

6.4.4 Self-Supply

All Inadvertent Energy Accounting services and Energy Imbalance Services shall be purchased from the ISO.

6.4.5 Verification of Adjustments

The ISO shall provide all necessary meter reading adjustment information required by the Transmission Owners to allow them to verify that meter reading adjustments were performed in accordance with ISO Procedures.

6.11 Schedule 11 - Penalty Cost Recovery

6.11.1 Direct Allocation of Costs Associated With NERC Penalty Assessments

6.11.1.1 Purpose and Objectives

Under the NERC Functional Model and the NERC Rules of Procedure, Registered Entities within a specific function may be assessed penalties by FERC, NERC, and/or NPCC for violations of NERC Reliability Standards. Pursuant to the terms and conditions of the Tariff and the ISO Procedures, certain tasks associated with Reliability Standards compliance may be performed either by the ISO and/or the Customers even when they are not the Registered Entity. This Schedule furnishes a mechanism by which either the ISO or a Customer may directly allocate, with FERC approval, monetary penalties imposed by FERC, NERC and/or NPCC on the Registered Entity to entity or entities whose conduct is determined by NERC or the Regional Entity to have led to a Reliability Standard violation. For purposes of this rate schedule, the terms "Customer" and "Market Participant" shall include Transmission Owners. The purpose of this schedule is to allow for cost allocation; nothing in this schedule is intended to affect the obligations of Registered Entities for compliance with NERC Reliability Standards. Penalties that are assessed against the ISO on or after the effective date of this Section shall be recoverable as provided in this Section regardless of the date of the violation(s) for which the penalty is assessed. Notwithstanding any provisions of the ISO's Tariffs or ISO Related Agreements, including those provisions requiring stakeholder approval for Section 205 filings in certain instances, the ISO has the independent authority to make Section 205 filings in accordance with the provisions of this Schedule 11 after consultation with the Management Committee as provided in Section 5.1.1(c) of the Services Tariff or Section 2.11.6(c) of the ISO OATT.

6.11.1.2 Definitions

All defined terms in this Schedule shall have the meaning given to them in the Tariff and the ISO Procedures unless otherwise stated below.

Compliance Monitoring and Enforcement Program (CMEP) - The program to be used by the NERC and the Regional Entities to monitor, assess and enforce compliance with the NERC Reliability Standards. As part of a Compliance Monitoring and Enforcement Program, NERC and the Regional Entities may, among other things, conduct investigations, determine fault and assess monetary penalties.

NERC Functional Model - Defines the set of functions that must be performed to ensure the reliability of the bulk power system. The NERC Reliability Standards establish the requirements of the responsible entities that perform the functions defined in the Functional Model.

NERC Reliability Standards - Those standards that have been developed by NERC and approved by FERC to ensure the reliability of the bulk power system.

NERC Rules of Procedure - The rules and procedures developed by NERC and approved by **the** FERC. These rules include the process by which a responsible entity, which is to perform a set of functions to ensure the reliability of the bulk power system, must register as the Registered Entity.

Registered Entity - The entity registered under the NERC Functional Model and NERC Rules of Procedures for the purpose of compliance with NERC Reliability Standards and responsible **for** carrying out the tasks within a NERC function without regard to whether a task or tasks are performed by another entity pursuant to the terms of the ISO's Tariffs and ISO Related Agreements.

Regional Entity - An entity to whom NERC has delegated Electric Reliability Organization (ERO) functions in a particular geographic region. For the ISO region, the applicable Regional Entity is the Northeast Power Coordinating Council (NPCC).

6.11.1.3 Allocation of Costs When the ISO is the Registered Entity

6.11.1.3.1 If FERC, NERC and/or NPCC assesses a monetary penalty against the ISO as the Registered Entity for a violation of a NERC Reliability Standard(s), and the conduct of a Customer or Customers contributed to the Reliability Standard violation(s) at issue, then the ISO may directly allocate such penalty costs or a portion thereof to the Customer or Customers whose conduct contributed to the Reliability Standards violation(s), provided that all of the following conditions have been satisfied:

(1) Pursuant to the CMEP, the Customer or Customers received notice and an opportunity to fully participate in the underlying CMEP proceeding;

(2) This CMEP proceeding produced a root cause finding, subsequently filed with FERC, that the Customer contributed, either in whole or in part, to the NERC Reliability Standards violation(s); and

(3) A NERC filing of the root cause finding identifying the Customer's or Customers' conduct as causing or contributing to the Reliability Standards violation charged against the ISO as the Registered Entity is made at FERC.

6.11.1.3.2 The ISO will notify the Customer or Customers found to have contributed to a violation, either in whole or in part, in the CMEP proceedings. Such notification shall set forth in writing the ISO's intent to invoke this Section 6.11.1.3 and directly assign the costs associated with a monetary penalty to the Customer or Customers. Such notification shall (i) state that the ISO believes the criteria for direct assignment and allocation of costs under this Schedule have been satisfied; and (ii) describe the underlying factual basis supporting a penalty cost assignment, including a description of the conduct contributing to the violation and the nature of the violation of the ISO Tariffs or ISO Related Agreement requirements.

6.11.1.3.3 A failure by a Customer or Customers to participate in the CMEP proceedings will not prevent the ISO from directly assigning the costs associated with a monetary penalty to the responsible Customer or Customers provided all other conditions set forth herein have been satisfied.

6.11.1.3.4 Where the Regional Entity's and/or NERC's root cause analysis finds that more than one party's conduct contributed to the Reliability Standards violation(s), the ISO shall inform all involved Customers and shall make an initial apportionment for purposes of the cost allocation on a basis reasonably proportional to the parties' relative fault consistent with NERC's root cause analysis.

6.11.1.3.5 If the ISO and the involved Customer(s) agree on the proportion of penalty cost allocation, such agreement shall be submitted to the FERC pursuant to Section 205 of the Federal Power Act for approval.

6.11.1.3.6 Should the Customer(s) disagree with the ISO's initial apportionment of the penalty based on each party's relative fault, then the parties shall meet in an attempt to informally resolve the penalty allocation. If the parties cannot agree informally, the matter shall be submitted to the FERC pursuant to Section 205 of the Federal Power Act.

6.11.1.3.7 Once there is a final order by FERC regarding the ISO's ability to directly assign the penalty amounts, the ISO shall include such amounts in the appropriate Customer's or Customers' next monthly invoice. Such payment amount shall be due with interest calculated at the FERC authorized refund rate from the date of payment of the penalty by the ISO, provided however, nothing precludes the Customer or Customers from paying such penalty when it becomes due for the ISO to avoid paying interest costs. If the Customer pays such penalty under protest when it becomes due and prior to a final order by FERC and such Customer is thereafter found not liable, the Customer is entitled to a refund of the penalty amount from the ISO, with interest calculated at the FERC authorized refund rate from the date the Customer pays the penalty.

6.11.1.4 Allocation of Costs When a Customer is the Registered Entity

6.11.1.4.1 If FERC, NERC and/or NPCC assesses a monetary penalty against a Customer as the Registered Entity for a violation of a NERC Reliability Standard(s), and the conduct of the ISO contributed to the Reliability Standard violation(s) at issue, then such Customer may directly allocate such penalty costs or portion thereof to the ISO to the extent the ISO's conduct contributed to the Reliability Standards violation(s), provided that the following conditions have been satisfied:

6.11.1.4.1.1 Pursuant to the CMEP, the ISO received notice and an opportunity to fully participate in the underlying CMEP proceeding;

6.11.1.4.1.2 This CMEP proceeding produced a root cause finding, subsequently filed with FERC, that the ISO contributed, either in whole or in part, to the NERC Reliability Standards violation(s); and

6.11.1.4.1.3 A NERC filing of the root cause finding identifying the ISO's conduct as causing or contributing to the Reliability Standards violation charged against the Customer as the Registered Entity is made at FERC.

6.11.1.4.2 The Customer shall notify the ISO if the ISO is found to have contributed to a violation, either in whole or in part in the CMEP proceedings. Such notification shall set forth in writing the Customer's intent to invoke this

Section 6.11.1.4 and directly assign the costs associated with a monetary penalty to the ISO. Such notification shall (i) state that the Customer believes the criteria for direct assignment and allocation of costs under this Schedule have been satisfied; and (ii) describe the underlying factual basis supporting a penalty cost assignment, including a description of the conduct contributing to the violation and, where applicable, the nature of the violation of the ISO Tariffs or ISO Related Agreement requirements.

6.11.1.4.3 A failure by the ISO to participate in the CMEP proceedings will not prevent the Customer from directly assigning the costs associated with a monetary penalty to the ISO provided all other conditions set forth herein have been satisfied.

6.11.1.4.4 Where the Regional Entity's and/or NERC's root cause analysis finds that the ISO's conduct contributed to the Reliability Standards violation(s), the Customer shall inform the ISO and shall make an initial apportionment for purposes of the cost allocation on a basis reasonably proportional to the parties' relative fault consistent with NERC's root cause analysis.

6.11.1.4.5 If the ISO and the involved Customer agree on a proportion of penalty cost allocation, such agreement shall be submitted to the FERC pursuant to Section 205 of the Federal Power Act.

6.11.1.4.6 Should the ISO disagree with the Customer's initial apportionment of the penalty based on each party's relative fault, then the parties shall meet in an attempt to informally resolve the penalty allocation. If the parties cannot agree informally, the matter shall be submitted to the FERC pursuant to Section 205 of the Federal Power Act.

6.11.1.4.7 Once there is a final order by FERC regarding the Customer's direct assignment of costs to the ISO, the ISO shall pay such amount with interest calculated at the FERC authorized refund rate from the date of payment of the penalty by the Registered Entity. The ISO shall thereafter pursue the recovery of such costs in accordance with Section 6.11.3 of this Schedule 11. Nothing precludes the ISO from paying such penalty when it becomes due for the Registered Entity to avoid paying interest costs. If the ISO pays such penalty under protest when it becomes due and prior to a final order by FERC and the ISO thereafter is found not liable, the ISO is entitled to a refund of the penalty amount from the Customer with interest calculated at the FERC authorized refund rate from the date of payment of the penalty by the ISO. The ISO shall thereafter refund any amounts that were collected from all Customers pursuant to Section 6.11.3 of this Schedule 11.

6.11.2 Allocation of Costs Associated With Other Reliability Penalty Assessments

6.11.2.1 Purpose and Objectives

The ISO is responsible for performing specific functions under other applicable state and federal regulatory requirements and may be assessed penalties by other regulatory bodies for violations of applicable regulatory requirements. Section 6.11.3 of this Schedule furnishes a mechanism by which the ISO may seek to recover monetary penalties imposed by such regulatory authorities. Penalties that are assessed against the ISO on or after the effective date of this Section shall be recoverable as provided in this Section regardless of the date of the violation(s) for which the penalty is assessed. Notwithstanding any provisions of the ISO's Tariffs or ISO Related Agreements, including those provisions requiring stakeholder approval for Section 205 filings in certain instances, the ISO has the independent authority to make Section 205 filings in accordance with the provisions of this Schedule 11 after consultation with the Management Committee as provided in Section 5.1.1(c) of the Services Tariff and in Section 2.11.6(c) of the ISO OATT.

6.11.3 Allocation of Costs Associated With Penalty Assessments

6.11.3.1

Where a particular Customer or Customers cannot be identified as the root cause of a penalty assessment against the ISO or if the ISO is assessed a penalty because of its own action or inaction that resulted in a reliability standard violation or a violation of applicable state or federal regulatory requirements, or if the ISO is allocated a penalty under Section 6.11.1.4 of this Schedule 11, the ISO may seek to recover such penalty costs in accordance with this Schedule 11. Any inclusion of penalty assessments in this Schedule 11 must first be approved by FERC on a case-by-case basis, as provided in *Reliability Standard Compliance and Enforcement in Regions with Regional Transmission Organizations or Independent System Operators*, Docket No. AD07-12-000, 122 FERC ¶ 61,247 (2008), or any successor policy. Notwithstanding any provisions of the ISO's Tariffs or ISO Related Agreements, including those provisions requiring stakeholder approval for Section 205 filings in certain instances, the ISO has the independent authority to make Section 205 filings in accordance with the provisions of this Schedule 11 after consultation with the Management Committee as provided in Section 5.1.1(c) of the Services Tariff or Section 2.11.6(c) of the ISO OATT.

6.11.3.2

Any and all costs associated with the imposition of NERC Reliability Standards penalties or penalties assessed by other regulatory authorities that may be assessed against the ISO either directly by NERC, other regulatory authority or allocated by a Customer or Customers under this Schedule shall be (i) paid by the ISO notwithstanding the limitation of liability provisions in this Tariff or the Services Tariff; and (ii) recovered as set forth in this Schedule 11, after consultation with the Management Committee as provided in Section 5.1.1(c) of the Services Tariff or Section 2.11.6(c) of the ISO OATT, or as otherwise approved by the FERC.

6.11.3.3

Penalties that are assessed against the ISO on or after the effective date of this section shall be recoverable as provided in this section regardless of the date of the violation(s) for which the penalty is assessed.

6.11.3.4 Allocation Basis and Invoicing

6.11.3.4.1 Allocation Basis. Any penalties that are permitted recovery under Section 6.11.3.0 of this Schedule 11 shall be allocated 50% to all Injection Billing Units and 50% to all Withdrawal Billing Units in the following manner. The rate to be applied to Injection Billing Units shall be the quotient of (i) 50% of (ii) the penalty costs to be recovered in the month divided by the total Injection Billing Units for the month. The rate to be applied to the Withdrawal Billing Units shall be the quotient of (i) 50% of (ii) the penalty costs to be recovered in the month divided by the total Withdrawal Billing Units for that month. The Injection Billing Unit rate shall then be multiplied by each Transmission Customer’s aggregate Injection Billing Units for the month, and the Withdrawal Billing Unit rate shall be multiplied by each Transmission Customer's aggregate Withdrawal Billing Units for the month..

6.11.3.4.2 Invoicing. Once there is a final order by FERC regarding the ISO's ability to recover penalty amounts, the ISO shall include such amounts in the next monthly invoice utilizing the billing units for the month of infraction. For purposes of this calculation, the "month of infraction" shall be the service month in which the violation occurred. Should the penalty be assessed for a violation occurring over multiple service months, the penalty to be recovered for each service month shall be the total penalty to be recovered through Section 6.11.3 of this Schedule divided by the number of months over which the violation occurred. Whenever practicable, the ISO shall recover this Rate Schedule 11 charge in the invoice issued in the month following the month in which the NYISO incurs the penalty charge. The ISO may recover penalty charges over several months if, in its discretion, the ISO determines such method of recovery to be a prudent course of action. In the event that one or more entities who otherwise would have been apportioned a share of the penalty are no longer Customers, the ISO shall adjust the remaining Customers' shares of the penalty costs, on a proportional basis, if necessary to fully recover the penalty charge.

16.2 Accounting for Transmission Losses

16.2.1 Charges

Subject to Attachment K of this Tariff, the ISO shall charge all Transmission Customers for transmission system losses based on the marginal cost of losses on either a bus or zonal basis, described below.

16.2.1.1 Loss Matrix

The ISO's RTD software will use a power flow model and penalty factors to estimate losses incurred in performing generation dispatch and billing functions for losses.

16.2.1.2 Residual Loss Payment

The ISO will determine the difference between the payments by Transmission Customers for losses and the payments to Suppliers for losses associated with all Transactions (LBMP Market or Transmission Service under Sections 3, 4, and 5 of this Tariff) for both the Day-Ahead and Real-Time Markets. The accounting for losses at the margin may result in the collection of more revenue than is required to compensate the Generators for the Energy they produced to supply the actual losses in the system. This over collection is termed residual loss payments. The ISO shall calculate residual loss payments revenue on an hourly basis and will credit them against the ISO's Residual Adjustment (See Rate Schedule 1 of the ISO OATT).

16.2.2 Computation of Residual Loss Payments

16.2.2.1 Marginal Losses Component LBMP

The ISO shall utilize the Marginal Losses Component of the LBMP on an Internal bus, an External bus, or a zone basis for computing the marginal contribution of each Transaction to the system losses. The computation of these quantities is described in this Attachment.

16.2.2.2 Marginal Losses Component Day-Ahead

The ISO shall utilize the Marginal Losses Component computed by computing the marginal contributions of each Transaction in the Day-Ahead Market.

16.2.2.3 Marginal Losses Component Real-Time

The ISO shall utilize the Marginal Losses Component calculated by the (i) RTD programs in most cases; (ii) by RTC_{15}, for External Transactions; or (iii) during intervals when the conditions specified in Part 16.1 of this Attachment J exist at Proxy Generator Buses, the RTC program, for computing the Marginal Losses Component associated with each Transaction scheduled in the Real-Time Market (or deviations from Transactions scheduled in the Day-Ahead Market). The computations will be performed on an RTD-interval basis and aggregated to an hourly total.

16.2.2.4 Charges

Charges to reflect the impact of Energy consumed by each Load, or transmitted by each Transmission Customer on Marginal Losses Component shall be determined as follows. Each of these charges may be negative.

16.2.2.5 Day-Ahead Charges

As part of the LBMP charged to all LSEs scheduled Day-Ahead to purchase Energy from the LBMP Market, the ISO shall charge each such LSE the product of: (a) the withdrawal scheduled Day-Ahead in each Load Zone by that LSE in each hour, in MWh; and (b) the Marginal Losses Component of the Day-Ahead LBMP in that Load Zone, in $/MWh.

As part of the TUC charged to all Transmission Customers whose transmission service has been scheduled Day-Ahead, the ISO shall charge each such Transmission Customer the product of (a) the amount of Energy scheduled Day-Ahead to be withdrawn by that Transmission Customer in each hour, in MWh; and (b) the Marginal Losses Component of the Day-Ahead

LBMP at the Point of Delivery (*i.e.*, Load Zone in which Energy is scheduled to be withdrawn or the bus where Energy is scheduled to be withdrawn under if Energy is scheduled to be withdrawn at a location outside the NYCA), minus the Marginal Losses Component of the Day-Ahead LBMP at the Point of Receipt, in $/MWh.

16.2.2.6 Real-Time Charges

As part of the LBMP charged to all LSEs that purchase Energy from the Real-Time LBMP Market, the ISO shall charge each such LSE the product of (a) the Actual Energy Withdrawals by that LSE in each Load Zone in each hour, minus the Energy withdrawal scheduled Day-Ahead in that Load Zone by that LSE for that hour, in MWh; and (b) the Marginal Losses Component of the Real-Time LBMP in that Load Zone, in $/MWh.

As part of the TUC charged to all Transmission Customers whose transmission service was scheduled after the determination of the Day-Ahead schedule, or who schedule additional transmission service after the determination of the Day-Ahead schedule, the ISO shall charge each such Transmission Customer the product of (a) Actual Energy Withdrawals by RTD in each hour, minus the amount of Energy scheduled Day-Ahead to be withdrawn by that Transmission Customer in that hour, in MWh; and (b) the Marginal Losses Component of the Real-Time LBMP at the Point of Delivery (*i.e.*, the Load Zone in which Energy is scheduled to be withdrawn or the external bus where Energy is scheduled to be withdrawn if Energy is scheduled to be withdrawn at a location outside the NYCA), minus the Marginal Losses Component of the Real-Time LBMP at the Point of Receipt, in $/MWh.

16.3 Transmission Service, Schedules and Curtailment

16.3.1 ISO's General Responsibilities

The ISO shall evaluate requests for transmission service submitted in the Day- Ahead scheduling process using Security Constrained Unit Commitment ("SCUC"), and will subsequently establish a Day-Ahead schedule. During the Dispatch Day, the ISO shall use the RTC_{15} to establish schedules for each hour of dispatch in that day.

The ISO shall use the information provided by RTC when making Curtailment decisions pursuant to the Curtailment rules described in Section 16.3.4 of this Attachment J.

16.3.2 Use of Decremental Bids to Dispatch Internal Generators

When dispatching Generators taking service under this Tariff to match changing conditions, the ISO shall treat Decremental Bids and Incremental Energy Bids simultaneously and identically as follows: (i) a generating facility selling energy in the LBMP Market may be dispatched downward if the LBMP at the Point of Receipt falls below the generating facility's Incremental Energy Bid; (ii) a Generator serving a transaction scheduled under this Tariff may be dispatched downward if the LBMP at the Generators's Point of Receipt falls below Decremental Bid for the Generator; (iii) a Supplier's Generator may be dispatched upward if the LBMP at the Generator's Point of Receipt rises above the Decremental or Incremental Energy Bid for the Generator regardless of whether the Generator is supplying Energy to the LBMP Market or supporting a transaction scheduled under this Tariff.

16.3.2.1 Use of Decremental Bids to Dispatch External Generators

When determining the amount of Energy that External Generators taking service under this Tariff are scheduled an hour ahead to produce, the ISO shall treat Decremental Bids and Incremental Energy Bids simultaneously and identically as follows: (i) a generating facility selling Energy in the LBMP Market will have its hour-ahead schedule reduced if the LBMP forecasted for the next hour by BME at the Point of Receipt falls below the generating facility's Incremental Energy Bid; (ii) a Generator serving a Transaction scheduled under this Tariff will have its schedule reduced if the LBMP forecasted for the next hour by RTC_{15} at the Generator's Point of Receipt falls below the Decremental Bid for the Generator; (iii) a Supplier's Generator will have its schedule increased if the LBMP forecasted for the next hour by RTC_{15} at the Generator's Point of Receipt rises above the Decremental or Incremental Energy Bid for the Generator, regardless of whether the Generator is supplying Energy to the LBMP Market or supporting a Transaction scheduled under this Tariff.

16.3.3 Day-Ahead Schedules

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

In the Day-Ahead schedule, the ISO shall use the SCUC to determine Generator schedules, Transmission Service schedules and DNIs with adjacent Control Areas. The ISO shall not use Decremental Bids submitted by Transmission Customers for Generators associated with Non-Firm Point-to-Point Transmission Service in the determination of the Day-Ahead schedule.

16.3.4 Reduction and Curtailment

If a Transmission Customer's Firm Point-to-Point Transmission Service or Network Integration Transmission Service is supporting an Internal Bilateral Transaction, or an Import, the ISO shall not reduce the Transmission Service.

If the Transaction was scheduled in the Day-Ahead Market, and the Day-Ahead Schedule for the Generator designated as the Supplier of Energy for that Bilateral Transaction called for that Generator to produce less Energy than was scheduled Day-Ahead to be consumed in association with that Transaction, the ISO shall supply the Load or Transmission Customer in an Export with Energy from the Day-Ahead LBMP Market. The Transmission Customer shall continue to pay the Day-Ahead TUC and in addition, the Supplier of Energy for the Bilateral Transaction, if it takes service under the ISO Services Tariff, shall pay the Day-Ahead LBMP price, at the Point of Receipt for the Transaction, for the replacement amount of Energy in (MWh) purchased in the LBMP Market. If the Supplier of Energy for the Bilateral Transaction does not take service under the ISO Services Tariff, it shall pay the greater of 150 percent of the Day-Ahead LBMP at the Point of Receipt for the Transaction or $100/MWh, for the replacement amount of Energy, as specified in this Tariff. These procedures shall apply regardless of whether the Generator designated to supply Energy in association with the Transaction was located inside or outside the NYCA.

If the Transaction was scheduled following the Day-Ahead Market, or the schedule for the Transaction was revised following the Day-Ahead Market, then the ISO shall supply the Load or Transmission Customer in an Export with Energy from the Real-Time LBMP Market, at the Real-Time LBMP, if necessary. If (1) the Generator designated to supply the Transaction is an Internal Generator, and it has been dispatched to produce less than the amount of Energy that is scheduled hour-ahead to be consumed in association with that Transaction; or (2) the Generator designated to supply the Transaction is an External Generator, and the amount of Energy it has been scheduled an hour ahead to produce (modified for any within-hour changes in DNI, if any) is less than the amount of Energy scheduled hour-ahead to be consumed in association with that Transaction; then the Transmission Customer shall pay the Real-Time TUC for the amount of Energy withdrawn in real-time in association with that Transaction minus the amount of Energy scheduled Day-Ahead to be withdrawn in association with that Transaction. In addition, to the extent that it has not purchased sufficient replacement Energy in the Day-Ahead Market, the Supplier of Energy for the Bilateral Transaction, if it takes service under the ISO Services Tariff, shall pay the Real-Time LBMP price, at the Point of Injection for the Transaction, for any additional replacement Energy (in MWh) necessary to serve the Load. If the Supplier of Energy for the Bilateral Transaction does not take service under the ISO Services Tariff, it shall pay the greater of 150 percent of the Real-Time LBMP at the Point of Injection for the Transaction or $100/MWh for the replacement amount of Energy, as specified in this Tariff. These procedures shall apply regardless of whether the Generator designated to supply Energy in association with that Transaction was located inside or outside the NYCA. Notwithstanding the foregoing, the amount of Transmission Service scheduled hour-ahead in the RTC for Transactions supplied by one of the following Generators shall retroactively be set equal to that Generator's actual output in each RTD interval:

16.3.4.1 Generators

16.3.4.1.1 Generators providing Energy under contracts executed and effective on or before November 18, 1999 (including PURPA contracts) in which the power purchaser does not control the operation of the supply source but would be responsible for penalties for being off-schedule;

16.3.4.1.2 Existing topping turbine Generators and extraction turbine Generators producing electric Energy resulting from the supply of steam to the district steam system located in New York City (LBMP Zone J) in operation on or before November 18, 1999 and/or topping or extraction turbine Generators utilized in replacing or repowering existing steam supplies from such units (in accordance with good engineering and economic design) that cannot follow schedules, up to a maximum total of 499 MW of such units; and

16.3.4.1.3 Existing intermittent (i.e., non-schedulable) renewable resource Generators in operation on or before November 18, 1999 within the NYCA, plus up to an additional 1000 MW of such Generators.

This procedure shall not apply for those hours the Generator supplying that Transaction has bid in a manner that indicates it is available to provide Regulation Service or Operating Reserves.

If the Energy injections scheduled by RTC_{15} at a Proxy Generator Bus are Curtailed at the request of the ISO then the Supplier of Transmission Customer whose transaction is Curtailed, in addition to paying the charge for replacement Energy necessary to serve the Load, shall be paid the product (if positive) of: (a) the Real-Time LBMP at the Proxy Generator Bus minus the higher of the Real-Time Bid price and zero; and (b) the Scheduled Energy Injection minus the Actual Energy Injections at that Proxy Generator Bus for the dispatch hour.

If the Transmission Customer was receiving Non-Firm Point-to-Point Transmission Service, and its Transmission Service was Reduced or Curtailed, the replacement Energy may be purchased in the Real-Time LBMP Market, at the Real-Time LBMP, by the Internal Load. An Internal Generator supplying Energy for such a Transmission Service that is Reduced or Curtailed may sell its excess Energy in the Real-Time LBMP Market.

The ISO shall not automatically reinstate Non-Firm Point-to-Point Transmission Service that was Reduced or Curtailed. Transmission Customers may submit new schedules to restore the Non-Firm Point-to-Point Transmission Service in the next RTC_{15} execution.

If a security violation occurs or is anticipated to occur, the ISO shall attempt to relieve the violation using the following procedures:

16.3.4.2 Procedures

16.3.4.2.1 Reduce Non-Firm Point-to-Point Transmission Service: Partially or fully physically Curtail External Non-Firm Transmission Service (Imports, Exports and Wheels Through) by changing DNI schedules to (1) Curtail those in the lowest NERC priority categories first; (2) Curtail within each NERC priority category, based on Decremental Bids; and Incremental Energy Bids for Imports and Wheel Throughs; and based on Sink Price Cap Bids for Exports and (3) prorate Curtailment of equal cost transactions within a priority category ;

16.3.4.2.2 Curtail non-Firm Point-to-Point Transmission Service: Curtail (through changing DNI) unscheduled non-Firm Transactions which contribute to the violation, starting with the lowest NERC priority category;

16.3.4.2.3 Dispatch Internal Generators, based on Incremental Energy Bids and Decremental Bids, including committing additional resources, if necessary;

16.3.4.2.4 Adjust the DNI associated with Transactions supplied by External Resources: Curtail External Firm Transactions until the Constraint is relieved by (1) Curtailing based on Incremental Energy Bids, Decremental Bids and Sink Price Cap Bids; and (2) except for External Transactions with minimum run times, prorating Curtailment of equal cost transactions;

16.3.4.2.5 Request Internal Generators to voluntarily operate in manual mode below minimum or above maximum dispatchable levels. When operating in manual mode, Generators will not be required to adhere to minimum ramp rates, nor will they be required to be respond to RTD Base Point Signals;

16.3.4.2.6 In over generation conditions, decommit Internal Generators based on Minimum Generation Bid rate in descending order; and

16.3.4.2.7 Invoke other emergency procedures including involuntary load Curtailment, if necessary.

16.3.5 Scheduling Transmission Service for External Transactions

The amount of Firm Transmission Service scheduled Day-Ahead for Bilateral Transactions which designate External Generators to supply Imports or Internal Generators to supply Exports will be equal to the amount of Energy scheduled to be consumed under those Transactions Day-Ahead. The amount of Firm Transmission Service scheduled in the RTC_{15} for Bilateral Transactions which designate External Generators to supply Imports or Internal Generators to supply Exports will be equal to the amount of Energy scheduled to be consumed under those Transactions in the RTC_{15}. The DNI between the NYCA and adjoining Control Areas will be adjusted as necessary to reflect the effects of any Curtailments of Import or Export Transactions. Additionally, any Curtailment or Reductions of schedules for Export Transactions will cause the scheduled amount of Transmission Service to change.

To the extent possible, Curtailments of External Transactions at the Proxy Generator Buses associated with the Cross-Sound Scheduled Line, the Neptune Scheduled Line, and the Linden VFT Scheduled Line shall be based on the transmission priority of the associated Advance Reservation for use of the Cross-Sound Scheduled Line, Neptune Scheduled Line, or the Linden VFT Scheduled Line (as appropriate).

The ISO shall use Decremental Bids supplied by Transmission Customers using External Generators to supply Wheels-Through to determine the amount of Energy those Generators are scheduled Day-Ahead to produce in each hour. This in turn will determine the Firm Transmission Service scheduled Day-Ahead to support those Transactions. The ISO shall also use Decremental Bids supplied by Transmission Customers using External Generators to supply Wheels-Through to determine the amount of Energy these Generators are scheduled to produce in the RTC_{15}, which, in turn, will determine the Transmission Service scheduled in the RTC to support those Transactions.

The ISO will not schedule a Bilateral Transaction which crosses an Interface between the NYCA and a neighboring Control Area if doing so would cause the DNI to exceed the Transfer Capability of that Interface.

The ISO shall not permit Market Participants to schedule External Transactions over the following eight scheduling paths:

16.3.5.1 External Transactions that are scheduled to exit the NYCA at the Proxy Generator Bus that represents the NYCA's Interface with the Control Area operated by the Independent Electricity System Operator of Ontario ("IESO"), and to sink in the Control Area operated by PJM Interconnection, LLC ("PJM");

16.3.5.2 External Transactions that are scheduled to exit the NYCA at the Proxy Generator Buses that represent the NYCA's common border with the Control Area operated by PJM, and to sink in the Control Area operated by IESO;

16.3.5.3 External Transactions that are scheduled to enter the NYCA at the Proxy Generator Buses that represent the NYCA's common border with the Control Area operated by PJM, and to source from the Control Area operated by IESO;

16.3.5.4 External Transactions that are scheduled to enter the NYCA at the Proxy Generator Bus that represents the NYCA's Interface with the Control Area operated by IESO, and to source from the Control Area operated by PJM;

16.3.5.5 Wheels Through the NYCA that are scheduled to enter the NYCA at the Proxy Generator Buses that represent the NYCA's common border with the Control Area operated by PJM, and to sink in the Control Area operated by the Midwest Independent Transmission System Operator, Inc. ("MISO");

16.3.5.6 Wheels Through the NYCA that are scheduled to exit the NYCA at the Proxy Generator Buses that represent the NYCA's common border with the Control Area operated by PJM, and to source from the Control Area operated by the MISO;

16.3.5.7 Wheels Through the NYCA that are scheduled to enter the NYCA at the Proxy Generator Bus that represents the NYCA's Interface with the Control Area operated by IESO, and to sink in the Control Area operated by the MISO; and

16.3.5.8 Wheels Through the NYCA that are scheduled to exit the NYCA at the Proxy Generator Bus that represents the NYCA's Interface with the Control Area operated by IESO, and to source from the Control Area operated by the MISO.

External Transactions at the Proxy Generator Buses that are associated with the Cross-Sound Scheduled Line, the Neptune Scheduled Line, and the Linden VFT Scheduled Line shall also be governed by Attachment N to the ISO Services Tariff.

2.19 Definitions - S

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

Scheduled Energy Injections: As defined in the ISO OATT.

Scheduled Energy Withdrawals: As defined in the ISO OATT.

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

SCUC: Security Constrained Unit Commitment, described in Section 4.2.4 of this ISO Services Tariff.

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

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

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

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

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

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

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

Service Agreement: The agreement, in the form of Attachment A to the Tariff, and any amendments or supplements thereto entered into by a Customer and the ISO of service under the Tariff, or any unexecuted Service Agreement, amendments or supplements thereto, that the ISO unilaterally files with the Commission.

Service Commencement Date: The date that the ISO begins to provide service pursuant to the terms of a Service Agreement, or in accordance with the Tariff.

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

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

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

Shutdown Period: An ISO approved period of time immediately following a shutdown order, such as a zero base point, that has been designated by the Customer, during which unstable operation prevents the unit from accurately following its base points.

Sink Price Cap Bid: A Bid Price 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.

Special Case Resource: Demand Side Resources capable of being interrupted upon demand, and Local Generators, rated 100 kW or higher, that are not visible to the ISO's Market Information System and that are subject to special rules, set forth in Section 5.12.11.1 of this ISO Services Tariff and related ISO Procedures, in order to facilitate their participation in the Installed Capacity market as Installed Capacity Suppliers. Special Case Resources that are not Local Generators, may be offered as synchronized Operating Reserves and Regulation Service and Energy in the Day-Ahead Market. Special Case Resources, using Local Generators rated 100 kw or higher, that are not visible to the ISO's Market Information System may also be offered as non-synchronized Operating Reserves.

Special Case Resource Capacity: The Installed Capacity Equivalent of the Unforced Capacity which has been sold by a Special Case Resource in the Installed Capacity market during the current Capability Period.

Start-Up Period: An ISO approved period of time immediately following synchronization to the Bulk power system, which has been designated by a Customer and bid into the Real-Time Market, during which unstable operation prevents the unit from accurately following its base points.

Station Power: Station Power shall mean the Energy used by a Generator:

1. for operating electric equipment located on the Generator site, or portions thereof, owned by the same entity that owns the Generator, which electrical equipment is used by the Generator exclusively for the production of Energy and any useful thermal energy associated with the production of Energy; and

2. for the incidental heating, lighting, air conditioning and office equipment needs of buildings, or portions thereof, that are: owned by the same entity that owns the Generator; located on the Generator site; and

3. used by the Generator exclusively in connection with the production of Energy and any useful thermal energy associated with the production of Energy.

Station Power does not include any Energy: (i) used to power synchronous condensers; (ii) used for pumping at a pumped storage facility or for charging a Limited Energy Storage Resource; or (iii) provided during a Black Start restoration by Generators that provide Black Start Capability Service.

Start-Up Bid: A Bid parameter that may vary hourly and that identifies the payment a Supplier requires to bring a Generator up to its specified minimum operating level from an offline state or a Demand Side Resource from a level of no Demand Reduction to its specified minimum level of Demand Reduction.

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

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

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

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

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

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

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

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

System Resource: A portfolio of Unforced Capacity provided by Resources located in a single ISO-defined Locality, the remainder of the NYCA, or any single External Control Area, that is owned by or under the control of a single entity, which is not the operator of the Control Area where such Resources are located, and that is made available, in whole or in part, to the ISO.

4.1 Market Services - General Rules

4.1.1 Overview

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

4.1.2 Independent System Operator Authority

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

4.1.3 Informational and Reporting Requirements

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

4.1.4 Scheduling Prerequisites

Each Customer shall be subject to a minimum Transaction size of one (1) megawatt ("MW") between each Point of Injection and Point of Withdrawal in any given hour. Each Transaction must be scheduled in whole megawatts.

4.1.5 Communication Requirements for Market Services

Customers may utilize a variety of communications facilities to access the ISO's OASIS and Bid/Post System, including but not limited to, conventional Internet service providers, wide area networks such as NERC net, and dedicated communications circuits. Customers shall arrange for and maintain all communications facilities for the purpose of communication of commercial data to the ISO. Each Customer shall be the customer of record for the telecommunications facilities and services its uses and shall assume all duties and responsibilities associated with the procurement, installation and maintenance of the subject equipment and software.

4.1.6 Customer Responsibilities

All purchasers in the Day-Ahead or Real-Time Markets who withdraw Energy within the NYCA or at an NYCA Interconnection with another Control Area must obtain Transmission Service under the ISO OATT. All Customers requesting service under the ISO Services Tariff to engage in Virtual Transactions must obtain Transmission Service under the ISO OATT.

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

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

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

4.1.7 Customer Compliance with Laws, Regulations and Orders

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

4.1.7.1 Violations of FERC's orders, rules and regulations also violate this Section 4.1.7 of the ISO Services Tariff. In particular, if FERC or a court of competent jurisdiction determines there has been a violation of FERC's regulations related to electric energy market manipulation (*see* 18 C.F.R. Section 1c.2, or any successor provision thereto), such violation is also a violation of this ISO Services Tariff if such violation affects or is related to the ISO Administered Markets.

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

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

4.1.8 Commitment for Reliability

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

Re-dispatching costs incurred as a result of reductions in Transfer Capability caused by Storm Watch ("Storm Watch Costs") shall be aggregated and recovered on a monthly basis by the ISO exclusively from Transmission Customers in Load Zone J. The ISO shall calculate Storm Watch Costs by multiplying the real-time Shadow Price of any binding constraint associated with a Storm Watch, by the higher of (a) zero; or (b) the scheduled Day-Ahead flow across the constraint minus the actual real-time flow across the constraint.

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

Generating units designated pursuant to the New York State Reliability Council's Local Reliability Rule I-R3 -- Loss of Generator Gas Supply (New York City) or I-R5 -- Loss of Generator Gas Supply (Long Island), as being required to burn an alternate fuel at designated minimum levels based on forecast Load levels in Load Zones J and K (for purposes of this Section 4.1.9, "eligible units"), shall be eligible to recover the variable operating costs associated with burning the required alternate fuel pursuant to the provisions of this Section 4.1.9. For purposes of this Section 4.1.9, the periods of time for which Consolidated Edison invokes Local Reliability Rule I-R3 or LIPA invokes Local Reliability Rule I-R5 and in which the eligible unit burns its required alternate fuel, including that period of time required to move into and out of Rule I-R3 or I-R5 compliance, shall be referred to as the "Eligibility Period." For Eligibility Periods, the eligible unit shall recover its variable operating costs associated with burning the required alternate fuel if and to the extent that such variable operating costs are not reflected in the reference level for that unit for the hours included in the Eligibility Period, pursuant to ISO procedures. To be recoverable, variable operating costs associated with burning the required alternate fuel must be incurred during an Eligibility Period and must be incurred only because Local Reliability Rule I-R3 or I-R5 was invoked.

Rules for determining: (i) variable operating costs associated with burning the required alternate fuel that would not have been incurred but for the requirement to burn the required alternate fuel as established by Local Reliability Rules I-R3 and I-R5; and (ii) Eligibility Periods shall be specified in ISO Procedures. Payments made by the ISO to the eligible unit to reimburse the variable operating costs paid pursuant to this Section 4.1.9 shall be in addition to any LBMP, Ancillary Service or other revenues received as a result of the eligible unit's Day-Ahead or Real-Time dispatch for that day.

There shall be no recovery of costs pursuant to this Section 4.1.9 for any hour for which the indexed variable operating costs of the required alternate fuel that is being burned pursuant to Rule I-R3 or I-R5 is less than the indexed variable operating costs for natural gas, as determined by the ISO.

The ISO shall make available for the Transmission Owner in whose subzone the Generator is located: (i) the identity of Generators determined by the ISO to be eligible to recover the variable operating costs associated with burning the required alternate fuel pursuant to the provisions of this section; (ii) the start and stop hours for each claimed Eligibility Period and (iii) the amount of alternative fuel for which the Generator has sought to recover variable operating costs.

4.5 Real-Time Market Settlements

Transmission Customers taking service under the Tariff, shall be subject to the Real-Time Market Settlement. Settlements for Limited Energy Storage Resources are governed by Rate Schedule 15.3 of this Services Tariff and are not governed by this Section 4.5. All withdrawals and injections not scheduled on a Day-Ahead basis, including Real-Time deviations from any Bilateral Transaction schedules, shall be subject to the Real-Time Market Settlement. Transmission Customers not taking service under this Tariff shall be subject to balancing charges as provided for under the ISO OATT. Settlements with External Suppliers or External Loads will be based upon hourly scheduled withdrawals or injections. Real-Time Market Settlements for injections by Resources supplying Regulation Service or Operating Reserves shall follow the rules which are described in Rate Schedules 15.3 and 15.4, respectively.

For the purposes of this section, the scheduled output of each of the following Generators in each RTD interval in which it has offered Energy shall retroactively be set equal to its actual output in that RTD interval:

(i) Generators providing Energy under contracts executed and effective on or before November 18, 1999 (including PURPA contracts) in which the power purchaser does not control the operation of the supply source but would be responsible for penalties for being off-schedule, with the exception of Generators under must-take PURPA contracts executed and effective on or before November 18, 1999 who have not provided telemetering to their local TO and historically have not been eligible to participate in the NYPP market, which will continue to be treated as TO Load modifiers under the ISO-administered markets;

(ii) Existing topping turbine Generators and extraction turbine Generators producing electric Energy resulting from the supply of steam to the district steam system located in New York City (LBMP Zone J) in operation on or before November 18, 1999 and/or topping or extraction turbine Generators utilized in replacing or repowering existing steam supplies from such units (in accordance with good engineering and economic design) that cannot follow schedules, up to a maximum total of 499 MW of such units.

This procedure shall not apply to a Generator for those hours it has bid in a manner that indicates it is available to provide Regulation Service or Operating Reserves.

In Sections 4.5.1, 4.5.2, 4.5.3, 4.5.4, 4.5.5 and 4.5.6 of this Tariff, references to Scheduled Energy Injections and Scheduled Energy Withdrawals shall encompass injections and withdrawals that are scheduled Day-Ahead, as well as injections and withdrawals that occur in connection with real-time Bilateral Transactions. In Sections 4.5.1, 4.5.3, 4.5.4 and 4.5.6 of this Tariff, references to Energy Withdrawals and Energy Injections shall not include Energy Withdrawals or Energy Injections in Virtual Transactions, or Energy Withdrawals or Energy Injections at Trading Hubs. Generators that are providing Regulation Service shall not be subject to the real-time Energy market settlement provisions set forth in this Section, but shall instead be subject to the Energy settlement rules set forth in Section 15.4.6 of Rate Schedule 15.3 of this ISO Services Tariff.

4.5.1 Settlement When Actual Energy Withdrawals Exceed Scheduled Energy Withdrawals Other Than Scheduled or Actual Withdrawals in Virtual Transactions

When the Actual Energy Withdrawals by a Customer over an RTD interval exceed the Energy withdrawals scheduled over that RTD interval, the ISO shall charge the Real-Time

LBMP for Energy equal to the product of: (a) the Real-Time LBMP calculated in that RTD interval for each applicable Load Zone; and (b) the difference between the Actual Energy Withdrawals and the Scheduled Energy Withdrawals at that Load Zone.

4.5.2 Settlement for Customers Scheduled To Sell Energy in Virtual Transactions in Load Zones

The Actual Energy Injection in a Load Zone by a Customer scheduled Day-Ahead to sell Energy in a Virtual Transaction is zero and the Customer shall pay a charge for the Energy imbalance equal to the product of: (a) the Real-Time LBMP calculated in that hour for the applicable Load Zone; and (b) the scheduled Day-Ahead Energy Injection of the Customer for that Hour in that Load Zone.

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

4.5.3.1 General Rule

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

4.5.3.2 Failed Transactions

If an Energy injection scheduled by RTC at a Proxy Generator Bus fails in the ISO's checkout process after RTC_{15}, the Supplier or Transmission Customer that was scheduled to make the injection will pay the Energy imbalance charge described above in Section 4.5.3.1. In addition, if the checkout failure occurred for reasons within the Supplier's or Transmission Customer's control it will be required to pay the "Financial Impact Charge" described below. The ISO's Market Mitigation and Analysis Department will determine whether the Transaction associated with an injection failed for reasons within a Supplier's or Transmission Customer's control.

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

If a Wheel Through fails for reasons within a Supplier's or Transmission Customer's control, the Financial Impact Charge will equal the sum of the Financial Impact Charge described in this section and the Financial Impact Charge described below in Section 4.5.4.2.

All Financial Impact Charges collected by the ISO shall be used to reduce the charges assessed under Rate Schedule 1 of this ISO Services Tariff. In the event that the Energy injections scheduled by RTC_{15} at a Proxy Generator Bus are Curtailed at the request of the ISO then the Supplier or Transmission Customer that is subjected to the Curtailment, in addition to the charge for Energy Imbalance, shall be eligible to receive an Import Curtailment Guarantee Payment for its curtailed Import pursuant to Attachment J of this ISO Services Tariff.

4.5.3.3 Capacity Limited Resources and Energy Limited Resources

For any hour in which: (i) a Capacity Limited Resource is scheduled to supply Energy, Operating Reserves, or Regulation Service in the Day-Ahead Market; (ii) the sum of its schedules to provide these services exceeds its bid-in upper operating limit; (iii) the Capacity Limited Resource requests a reduction for Capacity limitation reasons; and (iv) the ISO reduces the Capacity Limited Resource's upper operating limit to a level equal to, or greater than, its bid-in upper operating limit; the imbalance charge for Energy, Operating Reserve Service or Regulation Service imposed on that Capacity Limited Resource for that hour for its Day-Ahead Market obligations above its Capacity limited upper operating limit shall be equal to the product of: (a) the Real-Time price for Energy, Operating Reserve Service and Regulation Service; and (b) the Capacity Limited Resource's Day-Ahead schedule for each of these services minus the amount of these services that it has an obligation to supply pursuant to its ISO-approved schedule. When a Capacity Limited Resource's Day-Ahead obligation above its Capacity limited upper operating limit is balanced as described above, any real-time variation from its obligation pursuant to its Capacity limited schedules shall be settled pursuant to the methodology set forth in the first paragraph of this Section 4.5.3.

For any day in which: (i) an Energy Limited Resource is scheduled to supply Energy, Operating Reserves or Regulation Service in the Day-Ahead Market; (ii) the sum of its schedules to provide these services exceeds its bid-in Normal Upper Operating Limit; (iii) the Energy Limited Resource requests a reduction for Energy limitation reasons; and (iv) the ISO reduces the Energy Limited Resource's Day-Ahead Emergency Upper Operating Limitto a limit no lower than the Normal Upper Operating Limit; the Resource may be eligible to receive a Day-Ahead Margin Assurance Payment pursuant to Attachment J of this ISO Services Tariff.

4.5.3.4 Demand Reductions

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

When actual Demand Reduction over an hour from a Demand Reduction Provider that is not the LSE providing Energy service to the Demand Side Resource(s) that produced the reduction is less than the Demand Reduction scheduled over that hour, then (1) the LSE providing Energy service to the Demand Reduction Provider's Demand Side Resource(s) shall pay a Demand Reduction imbalance charge equal to the product of (a) the Day-Ahead LBMP calculated for that hour for the applicable Load bus and (b) the difference between the scheduled Demand Reduction and the actual Demand Reduction at that bus in that hour, and (2) the Demand Reduction Provider will pay an amount equal to (a) the product of (i) the higher of the Day-Ahead LBMP or the Real-Time LBMP calculated for that hour for the applicable Load bus, and (ii) the difference between the scheduled Demand Reduction and the actual Demand Reduction at that bus in that hour, and (b) minus the amount paid by the LSE providing service to the Demand Reduction Provider's Demand Side Resource(s) under (1), above.

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

4.5.4.1 General Rules

When a Customer's Actual Energy Withdrawals over an SCD interval are less than its Energy withdrawals scheduled Day-Ahead over that SCD interval, the Customer shall be paid the product of: (a) the Real-Time LBMP calculated in that RTD interval for each applicable Load Zone; and (b) the difference between the Scheduled Energy Withdrawals and the Actual Energy Withdrawals in that Load Zone.

4.5.4.2 Failed Transactions

If an Energy withdrawal at a Proxy Generator Bus scheduled by RTC fails in the ISO's checkout process after RTC_{15}, the Supplier or Transmission Customer that was scheduled to make the withdrawal will pay or be paid the energy imbalance charge described above in Section 4.5.4.1. In addition, if the checkout failure occurred for the reasons within the Supplier's or Transmission Customer's control it will be required to pay the "Financial Impact Charge" described below. The ISO's Market Mitigation and Analysis Department will determine whether the Transaction associated with a withdrawal failed for reasons within a Supplier's or Transmission Customer's control.

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

If a Wheel Through fails for reasons within a Supplier's or Transmission Customer's control, the Financial Impact Charge will equal the sum of the Financial Impact Charge described in this subsection and the Financial Impact Charge described above in Section 4.5.3.2.

All Financial Impact Charges collected by the ISO shall be used to reduce the charges assessed under Rate Schedule 15.1 of this ISO Services Tariff.

4.5.5 Settlement for Customers Scheduled To Purchase Energy in Virtual Transactions in Load Zones

The Actual Energy Withdrawal in a Load Zone by a Customer scheduled Day-Ahead to purchase Energy in a Virtual Transaction is zero and the Customer shall be paid the product of: (1) the Real-Time LBMP calculated in that hour for the applicable Load Zone; and (b) the scheduled Day-Ahead Energy Withdrawal of the Customer for that Hour in that Load Zone.

4.5.6 Settlement When Actual Energy Injections Exceed Scheduled Energy Injections

When Actual Energy Injections from a Generator over an RTD interval exceed the Energy injections scheduled Day-Ahead over the RTD interval the Supplier shall be paid the product of: (1) the Real-Time LBMP calculated in that RTD interval for the applicable Generator bus and (2) the difference between the lesser of (i) the Supplier's Actual Energy Injection or (ii) its Real-Time Scheduled Energy Injection for that RTD interval, plus any Compensable Overgeneration and the Supplier's Day-Ahead Scheduled Energy Injection over the RTD interval, unless the payment that the Supplier would receive for such injections would be negative (i.e., unless the LBMP calculated in that RTD interval at the applicable Generator's bus is negative) in which case the Supplier shall be paid the product of: (1) the Real-Time LBMP calculated in that RTD interval for the applicable Generator bus and (2) the difference between the Supplier's Actual Energy Injection for that RTD interval and the Supplier's Scheduled

Energy Injection over that RTD interval. Suppliers shall not be compensated for Energy in excess of their Real-Time Scheduled Energy Injections, except: (i) for Compensable Overgeneration; (ii) when the ISO initiates a large event reserve pickup or a maximum generation pickup under RTD-CAM; or (iii) when a Transmission Owner initiates a reserve pickup in accordance with a Reliability Rule, including a Local Reliability Rule. When there is no large event reserve pickup or maximum generation pickup, or when there is such an instruction but a Supplier is not located in the area affected by the maximum generation pickup, that Supplier shall not be compensated for Energy in excess of its Real-Time Scheduled Energy Injection plus any Compensable Overgeneration. When there is a reserve pickup, or when there is a maximum generation pickup and a Supplier is located in the area affected by it, and the Supplier was either scheduled to operate in RTD or subsequently was directed to operate by the ISO, that Supplier shall be paid based on the product of: (1) the Real-Time LBMP calculated in that RTD Interval for the applicable Generator bus; and (2) the Actual Energy Injection minus the Energy injection scheduled Day-Ahead. Generators will not be compensated for Energy produced during their start-up sequence.

4.5.7 Settlement for Trading Hub Energy Owner when POI is a Trading Hub

Each Trading Hub Energy Owner who bids a Bilateral Transaction into the Real-Time Market with a Trading Hub as its POI and has its schedule accepted by the ISO will pay the product of: (a) the hourly integrated Real-Time LBMP for the Load Zone associated with that Trading Hub; and (b) the Bilateral Transaction scheduled MW.

4.5.8 Settlement for Trading Hub Energy Owner when POW is a Trading Hub

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

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

The terms of Schedule 1 of the ISO OATT are hereby incorporated by reference into this Tariff. In applying the terms of Schedule 1 of the ISO OATT in connection with this Tariff, all terms in Schedule 1 of the ISO OATT that are applicable to “Transmission Customers” shall be similarly applicable to “Customers” under this Rate Schedule 1, and the ISO shall interpret all other defined terms and cross references in Schedule 1 that are specific to the ISO OATT consistent with the similar terms and provisions of this Tariff, unless otherwise specified.

17.3 Bilateral Transaction Bidding, Scheduling and Curtailment

17.3.1 Requests for Bilateral Transaction Schedules

Transmission Customers scheduling Transmission Service or to support a Bilateral Transaction with Energy supplied by an External Generator or Internal Generator shall submit the following information to the ISO:

17.3.1.1 Point of Injection location. For Transactions with Internal sources, the Point of Injection is the LBMP bus; for Transactions with Trading Hubs as their sources, the Point of Injection is the Trading Hub Generator bus; for Transactions with External sources, the Point of Injection is the Proxy Generator Bus; however, based upon such an advance notification to the ISO, an External Supplier will have the additional option of being modeled at a specific External LBMP bus (rather than an External Proxy Generator Bus) and being able to submit a bid curve. Otherwise, an External Supplier with Incremental or Decremental Bids at an External Proxy Generator Bus will be modeled as a single point price curve at that bus. An LBMP bus is a specific bus at which a Generator Shift Factor has been calculated, and for which LBMP will be calculated.

17.3.1.2 Point of Withdrawal location. For Internal Load, the Point of Withdrawal is the Load Zone in which the Load is situated or the bus at which that Load is interconnected to the Transmission System, if there is a revenue-quality real-time meter located at that bus (software constraints may initially limit the ability to specify buses as Points of Withdrawal); for delivery points outside the NYCA, the Point of Withdrawal is the Proxy Generator Bus; for Transactions with Trading Hubs as their sinks, the Point of Withdrawal is the Trading Hub Load bus;

17.3.1.3 Hourly MW schedules;

17.3.1.4 Minimum run times for Firm Point to Point Transmission Service, if any;

17.3.1.5 Whether Firm or Non-Firm Transmission Service is requested,

17.3.1.6 NERC Transaction Priorities for Bilateral Transactions involving External Generators, Exports, and Wheels Through;

17.3.1.7 A Sink Price Cap Bid for Export transactions up to the MW level of the desired schedule, a Decremental Bid for Import and Wheels Through transactions up to the MW level of the desired schedule;

17.3.1.8 For an Internal Generator, whether the Generator is On-Dispatch or Off-Dispatch;

17.3.1.9 The amount and location of any Ancillary Services the Transmission Customer will Self-Supply in accordance with and to the extent permitted by each of the Rate Schedules under the ISO OATT; and

17.3.1.10 Other data required by the ISO.

17.3.2 Bilateral Transaction Scheduling

17.3.2.1 ISO's General Responsibilities

The ISO shall determine, pursuant to ISO Procedures, the amount of Total Transfer Capability at each External Interface to be made available for scheduling.

The ISO shall evaluate requests for Transmission Service submitted in the Day-Ahead scheduling process using SCUC, and will subsequently establish a Day-Ahead schedule. During the Dispatch Day, the ISO shall use RTC_{15} to establish schedules for each hour of dispatch in that day.

The ISO shall use the information provided by RTC when making Curtailment decisions pursuant to the Curtailment rules described in this Attachment B.

17.3.2.2 Use of Decremental Bids to Dispatch Internal Generators

When dispatching Generators taking service under the ISO OATT to match changing conditions, the ISO shall treat Decremental Bids and Incremental Energy Bids simultaneously and identically as follows: (i) a generating facility selling Energy in the

LBMP Market may be dispatched downward if the LBMP at the Point of Receipt falls below the generating facility's Incremental Energy Bid; (ii) a Generator serving a Transaction scheduled under the ISO OATT may be dispatched downward if the LBMP at the Generator's Point of Receipt falls below the Decremental Bid for the Generator; (iii) a Supplier's Generator may be dispatched upward if the LBMP at the Generator's Point of Receipt rises above the Decremental or Incremental Energy Bid for the Generator regardless of whether the Generator is supplying Energy to the LBMP Market or supporting a Transaction scheduled under the ISO OATT.

17.3.2.3 Scheduling of Bilateral Transactions

Transmission Service for Bilateral Transactions shall be scheduled as follows:

(i) The ISO shall, following evaluation of the Bids submitted, schedule Transmission Service to support Transactions for the hours in which those Transactions may be accommodated.

(ii) The ISO shall treat all Internal Generators as dispatchable and all External Generators as non-dispatchable.

(iii) The ISO will use SCUC and RTD to determine schedules for Internal Generators and schedules for DNI with other Control Areas so that Firm Transmission

Service will be provided to any Bilateral Transaction Customer requesting Firm Transmission Service to the extent that is physically feasible.

(iv) The ISO shall not schedule Non-Firm Transmission Service Day-Ahead for a Transaction if Congestion Rents associated with that Transaction are positive, nor will the ISO schedule Non-Firm Transmission Service in the RTC if Congestion Rents associated with that Transaction are expected to be positive. All schedules for Non-Firm Point-to-Point Transmission Service are advisory only and are subject to Reduction if real-time Congestion Rents associated with those Transactions become positive. Transmission Customers receiving Non-Firm Transmission Service will be required to pay Congestion Rents during any delay in the implementation of Reduction (e.g., during the nominal five-minute RTD intervals that elapse before the implementation of Reduction).

17.3.2.4 Day-Ahead Bilateral Transaction Schedules

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

In the Day-Ahead schedule, the ISO shall use the SCUC to determine Generator schedules, Transmission Service schedules and DNIs with adjacent Control Areas. The ISO shall not use Decremental Bids submitted by Transmission Customers for Generators associated with Non-Firm Point-to-Point Transmission Service in the determination of the Day-Ahead schedule.

17.3.2.5 Reduction and Curtailment

If a Transmission Customer's Firm Point-to-Point Transmission Service or Network Integration Transmission Service is supporting an Internal Bilateral Transaction, or an Import, the ISO shall not reduce the Transmission Service.

If the Transaction was scheduled in the Day-Ahead Market, and the Day-Ahead Schedule for the Generator designated as the Supplier of Energy for that Bilateral Transaction called for that Generator to produce less Energy than was scheduled Day-Ahead to be consumed in association with that Transaction, the ISO shall supply the Load or Transmission Customer in an Export with Energy from the Day-Ahead LBMP Market.

The Transmission Customer shall continue to pay the Day-Ahead TUC and, in addition, if it takes service under this Tariff, the Supplier of Energy for the Bilateral Transaction shall pay the Day-Ahead LBMP price, at the Point of Receipt for the Transaction, for the replacement amount of Energy (in MWh) purchased in the LBMP Market. If the Supplier of Energy for the Bilateral Transaction does not take service under this Tariff, it shall pay the greater of 150 percent of the Day-Ahead LBMP at the Point of Receipt for the Transaction or $ 100/MWh for the replacement amount of energy, as specified in the OATT. These procedures shall apply regardless of whether the Generator designated to supply Energy in association with the Transaction was located inside or outside the NYCA.

If the Transaction was scheduled following the Day-Ahead Market, or the schedule for the Transaction was revised following the Day-Ahead Market, then the ISO shall supply the Load or Transmission Customer in an Export with Energy from the Real-Time LBMP Market, at the Real-Time LBMP, if necessary, if (1) the Generator designated to supply the Transaction is an Internal Generator, and it has been dispatched to produce less than the amount of Energy that is scheduled hour-ahead to be consumed in association with that Transaction; or (2) the

Generator designated to supply the Transaction is an External Generator, and the amount of Energy it has been scheduled an hour ahead to produce (modified for within-hour changes in DNI, if any) is less than the amount of Energy scheduled hour-ahead to be consumed in association with that Transaction; then the Transmission Customer shall pay the Real-Time TUC for the amount of Energy withdrawn in real time in association with that Transaction minus the amount of Energy scheduled Day-Ahead to be withdrawn in association with that Transaction. In addition, to the extent that it has not purchased sufficient replacement Energy in the Day-Ahead Market, the Supplier of Energy for the Bilateral Transaction, if it takes service under this Tariff, shall pay the Real-Time LBMP price, at the Point of Injection for the Transaction, for any additional replacement Energy (in MWh) necessary to serve the Load. If the Supplier of Energy for the Bilateral Transaction does not take service under this Tariff, it shall pay the greater of 150 percent of the Real-Time LBMP at the Point of Injection for the Transaction or $100/MWh for the replacement amount of Energy, as specified in the OATT. These procedures shall apply regardless of whether the Generator designated to supply Energy in association with that Transaction was located inside or outside the NYCA. Notwithstanding the foregoing, the amount of Transmission Service scheduled hour-ahead in the RTC for Transactions supplied by one of the following Generators shall retroactively be set equal to that Generator's actual output in each RTD interval:

(i) Generators providing Energy under contracts executed and effective on or before November 18, 1999 (including PURPA contracts) in which the power purchaser does not control the operation of the supply source but would be responsible for penalties for being off-schedule;

(ii) Existing topping turbine Generators and extraction turbine Generators producing electric Energy resulting from the supply of steam to the district steam system located in New York City (LBMP Zone J) in operation on or before November 18, 1999 and/or topping or extraction turbine Generators utilized in replacing or repowering existing steam supplies from such units (in accordance with good engineering and economic design) that cannot follow schedules, up to a maximum total of 499 MW of such units; and

(iii) Existing intermittent (i.e., non-schedulable) renewable resource Generators in operation on or before November 18, 1999 within the NYCA, plus up to an additional 1000 MW of such Generators.

This procedure shall not apply for those hours the Generator supplying that Transaction has bid in a manner that indicates it is available to provide Regulation Service or Operating Reserves. If the Energy injections scheduled by RTC_{15} at a Proxy Generator Bus are Curtailed at the request of the ISO then the Supplier or Transmission Customer whose transaction is Curtailed, in addition to paying the charge for replacement Energy necessary to serve the Load and the charge to balance the TUC, as appropriate, shall be paid the product (if positive) of: (a) the Real-Time LBMP at the Proxy Generator Bus minus the higher of the Real-Time Bid price and zero; and (b) the Scheduled Energy Injection minus the Actual Energy Injections at that Proxy Generator Bus for the dispatch hour.

If the Transmission Customer was receiving Non-Firm Point-to-Point Transmission Service, and its Transmission Service was Reduced or Curtailed, the replacement Energy may be purchased in the Real-Time LBMP Market, at the Real-Time LBMP, by the Internal Load. An

Internal Generator supplying Energy for such a Transmission Service that is Reduced or Curtailed may sell its excess Energy in the Real-Time LBMP Market.

The ISO shall not automatically reinstate Non-Firm Point-to-Point Transmission Service that was Reduced or Curtailed. Transmission Customers may submit new schedules to restore the Non-Firm Point-to-Point Transmission Service in the next RTC_{15} execution.

If a security violation occurs or is anticipated to occur, the ISO shall attempt to relieve the violation using the following procedures:

(i) Reduce Non-Firm Point-to-Point Transmission Service: Partially or fully physically Curtail External Non-Firm Transmission Service (Imports, Exports and Wheels-Through) by changing DNI schedules to (1) Curtail those in the lowest NERC priority categories first; (2) Curtail within each NERC priority category based on Incremental Energy Bids, Decremental Bids, or Sink Price Cap Bids; and (3) prorate Curtailment of equal cost transactions within a priority category.

(ii) Curtail Non-Firm Point-to-Point Transmission Service: Curtail (through changing DNI) unscheduled Non-Firm Transactions which contribute to the violation, starting with the lowest NERC priority category.

(iii) Dispatch Internal Generators, based on Incremental Energy Bids and Decremental Bids, including committing additional resources, if necessary;

(iv) Adjust the DNI associated with Transactions supplied by External resources: Curtail External Firm Transactions until the Constraint is relieved by (1) Curtailing based on Incremental Energy Bids, Decremental Bids or Sink Price Cap Bids, and (2) except for External Transactions with minimum run times, prorating Curtailment of equal cost transactions;

(v) Request Internal Generators to voluntarily operate in manual mode below minimum or above maximum dispatchable levels. When operating in manual mode, Generators will not be required to adhere to the one percent minimum ramp rate set forth in Article 4 of the ISO Services Tariff, nor will they be required to respond to RTD Base Point Signals;

(vi) In overgeneration conditions, decommit Internal Generators based on Minimum Generation Bid rate in descending order; and

(vii) Invoke other emergency procedures including involuntary Load Curtailment, if necessary.

17.3.2.6 Scheduling Transmission Service for External Transactions

The amount of Firm Transmission Service scheduled Day-Ahead for Bilateral Transactions which designate External Generators to supply Imports or Internal Generators to supply Exports will be equal to the amount of Energy scheduled to be consumed under those Transactions Day-Ahead. The amount of Firm Transmission Service scheduled in the RTC_{15} for Bilateral Transactions which designate External Generators to supply Imports or Internal Generators to supply Exports will be equal to the amount of Energy scheduled to be consumed under those Transactions in RTC_{15}. The DNI between the NYCA and adjoining Control Areas will be adjusted as necessary to reflect the effects of any Curtailments of Import or Export Transactions. Additionally, any Curtailment or Reductions of schedules for Export Transactions will cause the scheduled amount of Transmission Service to change.

To the extent possible, Curtailments of External Transactions at the Proxy Generator Bus associated with the Cross-Sound Scheduled Line, the Neptune Scheduled Line, and the Linden VFT Scheduled Line shall be based on the transmission priority of the associated Advance

Reservation for use of the Cross-Sound Scheduled Line, the Neptune Scheduled Line, or the Linden VFT Scheduled Line (as appropriate).

The ISO shall use Decremental Bids supplied by Transmission Customers using External Generators to supply Wheels-Through to determine the amount of Energy those Generators are scheduled Day-Ahead to produce in each hour. This in turn will determine the Firm Transmission Service scheduled Day-Ahead to support those Transactions. The ISO shall also use Decremental Bids supplied by Transmission Customers using External Generators to supply Wheels-Through to determine the amount of Energy these Generators are scheduled to produce in RTC_{15}, which, in turn, will determine the Transmission Service scheduled in RTC_{15} to support those Transactions.

The ISO will not schedule a Bilateral Transaction which crosses an Interface between the NYCA and a neighboring Control Area if doing so would cause the DNI to exceed the Transfer Capability of that Interface.

The ISO shall not permit Market Participants to schedule External Transactions over the following eight scheduling paths:

1. External Transactions that are scheduled to exit the NYCA at the Proxy Generator Bus that represents its Interface with the Control Area operated by the Independent Electricity System Operator of Ontario ("IESO"), and to sink in the Control Area operated by PJM Interconnection, LLC ("PJM");
2. External Transactions that are scheduled to exit the NYCA at the Proxy Generator Buses that represent the NYCA's common border with the Control Area operated by PJM, and to sink in the Control Area operated by IESO;

3. External Transactions that are scheduled to enter the NYCA at the Proxy Generator Buses that represent the NYCA’s common border with the Control Area operated by PJM, and to source from the Control Area operated by IESO;
4. External Transactions that are scheduled to enter the NYCA at the Proxy Generator Bus that represents the NYCA’s Interface with the Control Area operated by IESO, and to source from the Control Area operated by PJM;
5. Wheels Through the NYCA that are scheduled to enter the NYCA at the Proxy Generator Buses that represent the NYCA’s common border with the Control Area operated by PJM, and to sink in the Control Area operated by the Midwest Independent Transmission System Operator, Inc. (“MISO”);
6. Wheels Through the NYCA that are scheduled to exit the NYCA at the Proxy Generator Buses that represent the NYCA’s common border with the Control Area operated by PJM, and to source from the Control Area operated by the MISO;
7. Wheels Through the NYCA that are scheduled to enter the NYCA at the Proxy Generator Bus that represents the NYCA’s Interface with the Control Area operated by IESO, and to sink in the Control Area operated by the MISO; and
8. Wheels Through the NYCA that are scheduled to exit the NYCA at the Proxy Generator Bus that represents the NYCA’s Interface with the Control Area operated by IESO, and to source from the Control Area operated by the MISO.

External Transactions at the Proxy Generator Buses that are associated with the Cross-Sound Scheduled Line, the Neptune Scheduled Line, and the Linden VFT Scheduled Line shall also be governed by Attachment N to the ISO Services Tariff.