New York Independent System Operator

Market Administration And Control Area Services Tariff

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ARTICLE 1

INTRODUCTION AND PURPOSE

The New York Independent System Operator Market Administration and Control Area Services Tariff (the "ISO Services Tariff" or the "Tariff") sets forth the provisions applicable to the services provided by the ISO related to its administration of competitive markets for the sale and purchase of Energy and Capacity and for the payments to Suppliers who provide Ancillary Services to the ISO in the ISO Administered Markets ("Market Services") and the ISO's provision of Control Area Services ("Control Area Services"), including services related to ensuring the reliable operation of the NYS Power System. The Tariff addresses the Market Services and the Control Area Services provided by the New York ISO, and the terms and conditions under which those services are provided. Market Services are addressed in Article 4 of the Tariff, and Control Area Services are addressed in Article 5 of the Tariff. Transmission Service is provided under the ISO's Open Access Transmission Tariff (the "ISO OATT"). All references to Sections, Schedules and Attachments, unless otherwise noted, are references to the ISO Services Tariff.

ARTICLE 2

DEFINITIONS

2.0 Definitions

The following definitions are applicable to the ISO Services Tariff:

2.1 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.

2.2 Adverse Conditions

Those conditions of the natural or man-made environment that threaten the adequate reliability of the NYS Power System, including, but not limited to, thunderstorms, hurricanes, tornadoes, solar magnetic flares and terrorist activities.

2.3 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 have 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.

2.4 Ancillary Services

Services necessary to support the transmission of Energy from Generators to Loads, while maintaining reliable operation of the NYS Power System in accordance with Good Utility Practice and Reliability Rules. Ancillary Services include Scheduling, System Control and Dispatch Service; Reactive Supply and Voltage Support Service (or “Voltage Support Service”); Regulation and Frequency Response Service (or “Regulation Service”); Energy Imbalance Service; Operating Reserve Service (including Spinning Reserve, 10-Minute Non-Synchronized Reserves and 30-Minute Reserves); and Black Start Capability.

2.5 Application

A request to provide or receive service pursuant to the provisions of the ISO Services Tariff, that includes all information reasonably requested by the ISO.

2.6 Automatic Generation Control (“AGC”)

The automatic regulation of the power output of electric Generators within a prescribed range in response to a change in system frequency, or tie-line loading, to maintain system frequency or scheduled interchange with other areas within predetermined limits.

2.7 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.

2.8 Availability

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

2.9 Back-Up Operation

The dispatch and scheduling of the NYS Power System performed by the Transmission Owners, pursuant to ISO Procedures, when the ISO's ability to operate the NYS Power System has been impaired.

2.10 Balancing Market Evaluation ("BME")

An evaluation performed for the hour in which the dispatch occurs. The BME begins ninety (90) minutes before the beginning of the hour in which dispatch occurs. Based upon the Day-Ahead commitment and updated Load forecasts and Generator schedules, BME will assess new Bids for the Locational Based Marginal Pricing ("LBMP") Markets and requests for new Bilateral Transaction schedules for the Dispatch Hour to which the SCUC applies. BME will redispatch Internal Generators, schedule External Generators, schedule new Bilateral Transactions if feasible, update Desired Net Interchanges if needed, and Reduce or Curtail Bilateral Transactions with non-Firm and Firm Transmission Service as needed for the Dispatch Hour for which the SCUC applies.

2.11 Base Point Signals

Electronic signals sent from the ISO and ultimately received by Generators specifying the scheduled MW output for the Generator. Security Constrained Dispatch ("SCD") Base Point Signals are typically sent to Generators on a nominal five (5) minute basis. AGC Base Point Signals are typically sent to Generators on a nominal six (6) second basis.

2.12 Bid/Post System

An electronic information system used to allow the posting of proposed transmission schedules and Bids for Energy and Ancillary Services by Market Participants for use by the ISO and to allow the ISO to post Locational Based Marginal Prices and schedules.

2.13 Bid

Offer to purchase and/or sell Energy, Transmission Congestion Contracts and/or Ancillary Services at a specified price that is duly submitted to the ISO pursuant to ISO Procedures.

2.14 Bid Price

The price at which the Supplier offering the Bid is prepared to provide the product or service, or the buyer offering the Bid is willing to pay to receive such product or service.

2.15 Bid Production Cost

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

2.16 Bilateral Transaction

A Transaction between two or more parties for the purchase and/or sale of Capacity, Energy, and/or Ancillary Services other than those in the ISO Administered Markets.

2.17 Capability Period

Six (6) month periods which are established as follows: (1) from May 1 through October 31 of each year ("Summer Capability Period"); and (2) from November 1 of each year through April 30 of the following year ("Winter Capability Period"); or such other periods as may be determined by the Operating Committee of the ISO. A Summer Capability Period followed by a Winter Capability Period shall be referred to as a "Capability Year." Each Capability Period shall consist of On-Peak and Off-Peak periods.

2.18 Capacity

The capability to generate or transmit electrical power, measured in megawatts ("MW").

2.19 Centralized Transmission Congestion Contracts ("TCC") Auction ("Auction")

The process by which TCCs are released for sale for the Centralized TCC Auction period, through a bidding process administered by the ISO or an auctioneer.

2.20 Class A Unit

A Generator or Dispatchable Load that participates in nominal five (5) minute SCD dispatch.

2.21 Class B Unit

A Generator or Dispatchable Load that is not participating in the nominal five (5) minute SCD dispatch, but offers to provide spinning reserves to the ISO.

2.22 Code of Conduct

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

2.23 Commission ("FERC")

The Federal Energy Regulatory Commission, or any successor agency.

2.24 Completed Application

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

2.25 Confidential Information

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

2.26 Congestion

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

2.27 Congestion Component

The component of the LBMP measured at a location or the Transmission Usage Charge between two locations that is attributable to the cost of transmission Congestion.

2.28 Congestion Rent

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

2.29 Congestion Rent Shortfall

A condition in which the Congestion Rent revenue collected by the ISO over a defined time period is less than the amount of Congestion Rent revenue that the ISO is obligated under the ISO OATT to pay out to the Primary Holders of TCCs.

2.30 Constraint

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

2.31 Contingency

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

2.32 Control Area

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

2.33 Curtailment or Curtail

A reduction in Firm or non-Firm Transmission Service in response to a transmission capacity shortage as a result of system reliability conditions.

2.34 Customer

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

2.35 Day-Ahead

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

2.36 Day-Ahead LBMP

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

2.37 Day-Ahead Market

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

2.38 Decremental Bid

A monotonically increasing bid curve provided by an entity engaged in a Bilateral Transaction to indicate the LBMP below which that entity is willing to reduce its Generator's output or have its Transmission Service Curtailed, and purchase Energy in the LBMP Markets. If Decremental Bids are not voluntarily provided by such entities, the ISO will enter a default Decremental Bid.

2.39 Demand Side Resources

Resources that result in the reduction of a Load in a responsive and measurable manner and within time limits established in the ISO Procedures.

2.40 Dependable Maximum Net Capability ("DMNC")

The sustained maximum net output of a Generator, as demonstrated by the performance of a test or through actual operation, averaged over a continuous time period as defined in the ISO Procedures.

2.41 Desired Net Interchange ("DNI")

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

2.42 Direct Sale

The sale of TCCs directly to a buyer by the Primary Owner through a non-discriminatory auditable sale conducted on the ISO's OASIS, in compliance with the requirements and restrictions set forth in Commission Order Nos. 888 et seq. and 889 et seq.

2.43 Dispatchable

A Generator or Load that is capable of responding to real-time control from the ISO.

2.44 Dispatch Day

The twenty-four (24) hour period commencing at the beginning of each day (0000 hour).

2.45 Dispute Resolution Administrator ("DRA")

An individual hired by the ISO to administer the Dispute Resolution Process established in the ISO Tariffs and ISO Agreement.

2.46 Dispute Resolution Process ("DRP")

The procedures: (1) described in the ISO Tariffs and the ISO Agreement that are used to resolve disputes between Market Participants and the ISO involving services provided under the ISO Tariffs (excluding applications for rate changes or other changes to the ISO Tariffs or rules relating to such services); and (2) described in the ISO/NYSRC Agreement that are used to resolve disputes between the ISO and NYSRC involving the implementation and/or application of the Reliability Rules.

2.47 Emergency

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

2.48 Emergency State

The state that the NYS Power System is in when an abnormal condition occurs that requires automatic or immediate, manual action to prevent or limit loss of the NYS Transmission System or Generators that could adversely affect the reliability of the NYS Power System.

2.49 Energy (“MWh”)

A quantity of electricity that is bid, produced, purchased, consumed, sold, or transmitted over a period of time, and measured or calculated in megawatt hours.

2.50 Excess Congestion Rents

Congestion revenues collected by the ISO that are in excess of its payment obligations to those parties with which it has such a financial obligation. Excess Congestion Rents may arise if Congestion occurs and if the Transfer Capability of the transmission system is not exhausted by the set of TCCs and Grandfathered Rights that have been allocated at the completion of the Centralized TCC Auction.

2.51 Existing Transmission Capacity for Native Load

Transmission capacity reserved on a Transmission Owner's transmission system to serve the Native Load Customers of the current Transmission Owners (as of the filing date of the original ISO Tariff - January 31, 1997). This includes transmission capacity required: (1) to deliver the output from operating facilities located out of a Transmission Owner's Transmission District; (2) to deliver power purchased under power supply contracts; and (3) to deliver power purchased under third party agreements (i.e., Non-Utility Generators). Existing Transmission Capacity for Native Load is listed in Attachment L of the ISO OATT.

2.52 Existing Transmission Agreement ("ETA")

An agreement between two or more Transmission Owners, or between a Transmission Owner and another entity, as defined in the ISO Agreement and the ISO OATT.

2.53 Exports

Purchases from the LBMP Market where the Energy is delivered to an NYCA interconnection with another Control Area.

2.54 External

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

2.55 External Transactions

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

2.56 Federal Power Act ("FPA")

The Federal Power Act, as may be amended from time-to-time (See 16 U.S.C. §§ 796 et seq.)

2.57 Firm Point-To-Point Transmission Service

Transmission Service under this Tariff that is scheduled between specified Points of Receipt and Delivery pursuant to Part II of this Tariff. Firm Point-To-Point Transmission Service is service for which the Transmission Customer has agreed to pay the Congestion associated with its service. A Transmission Customer may fix the price of Congestion associated with its Firm Point-To-Point Transmission Service by acquiring sufficient TCCs with the same Points of Receipt and Delivery as its Transmission Service.

2.58 Firm Transmission Service

Transmission service requested by a Transmission Customer willing to pay Congestion Rent.

2.59 First Settlement

The process of establishing binding financial commitments on the part of Customers participating in the Day-Ahead Market based on Day-Ahead LBMP.

2.60 Generator

A facility capable of supplying Energy, Capacity and/or Ancillary Services that is accessible to the NYCA or the Energy, Capacity and/or Ancillary Services from such facilities.

2.61 Generator Classes

The type of Generator (e.g., nuclear, gas turbine, fossil, hydro) which is used by the ISO to determine criteria that must be met for that Generator to qualify as a source of Installed Capacity.

2.62 Good Utility Practice

Any of the practices, methods or acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods or acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather to delineate acceptable practices, methods, or acts generally accepted in the region.

2.63 Government Bonds

Tax-exempt bonds issued by the New York Power Authority pursuant to Section 103 and related provisions of the Internal Revenue Code, 26 U.S.C. § 103.

2.64 Grandfathered Rights

The transmission rights associated with: (1) Modified Wheeling Agreements; (2) Transmission Facility Agreements with transmission wheeling provisions; (3) Third Party Transmission Wheeling Agreements ("TWA") where the party entitled to exercise the transmission rights associated with such Agreements has chosen, as provided in the Tariff, to retain those rights rather than to convert those rights to TCCs; and (4) Existing Transmission Capacity for Native Load, Table 3 of Attachment L to the ISO OATT. Upon the expiration or termination of Grandfathered Rights, the associated transmission capacity is converted to Residual Transmission Capacity.

2.65 Grandfathered TCCs

The TCCs associated with: (1) Modified Wheeling Agreements; (2) Transmission Facility Agreements with transmission wheeling provisions; (3) Third Party ("TWA") where the party entitled to exercise the transmission rights associated with such Agreements has chosen, as provided by the Tariff, to convert those rights to TCCs; and (4) Existing Transmission Capacity for Native Load, Table 3 of Attachment L to the ISO OATT.

2.66 Hour-Ahead Bid

A Bid submitted at least ninety (90) minutes before the dispatch hour to which it applies.

2.67 Imports

Transmission Service originating within another Control Area and wheeling into the NYCA.

2.68 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.

2.69 Incremental Bid

A monotonically increasing Bid curve with a finite number of break points (currently six break points), that indicates an entity's willingness to supply Energy at certain prices to the ISO Administered LBMP Markets.

2.70 Independent System Operator ("ISO")

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

2.71 Independent System Operator Agreement ("ISO Agreement")

The agreement that establishes the New York ISO.

2.72 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.

2.73 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.

2.74 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.

2.75 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.

2.76 Interface

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

2.77 Interface MW - Mile Methodology

The procedure used to allocate Residual TCCs, revenues from the sale of certain TCCs, and Excess Congestion Rents between the Transmission Owners as described in Attachment K to the ISO OATT.

2.78 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.

2.79 Internal Transactions

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

2.80 Interruptible Load Resources

A Load that is obligated under a contract to be interrupted when required by the ISO. Such a Load must demonstrate that it is capable of quantifiable reduction in consumption in response to the ISO’s instructions.

2.81 ISO Administered Markets

The Day-Ahead Market and the Real-Time Market (collectively the “LBMP Markets”) and any other market administered by the ISO.

2.82 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.

2.83 ISO OATT

The ISO Open Access Transmission Tariff.

2.84 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.

2.85 ISO Related Agreements

Collectively, the ISO Agreement, the ISO/TO Agreement, the NYSRC Agreement, and the ISO/NYSRC Agreement.

2.86 ISO Services Tariff (the "Tariff")

The ISO Market Administration and Control Area Services Tariff.

2.87 ISO Tariffs

The ISO OATT and the ISO Services Tariff, collectively.

2.88 LBMP Market(s)

The Real-Time Market or the Day-Ahead Market or both.

2.89 LIPA Tax Exempt Bonds

Obligations of the Long Island Power Authority, the interest on which is not included in gross income under the Internal Revenue Code.

2.90 Load

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

2.91 Load Serving Entity ("LSE")

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

2.92 Load Shedding

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

2.93 Load Zone

One (1) of eleven (11) geographical areas located within the NYCA that is bounded by one (1) or more of the fourteen (14) New York State Interfaces. During the implementation of the LBMP Markets, all Loads located within the same Load Zone pay the same Day-Ahead LBMP and the same Real-Time LBMP for Energy purchased in those markets.

2.94 Local Furnishing Bonds

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

2.95 Locality

A single LBMP Load Zone or set of adjacent LBMP Load Zones within one Transmission District within which a minimum level of Installed Capacity must be maintained.

2.96 Local Reliability Rule

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

2.97 Locational Based Marginal Pricing ("LBMP")

A pricing methodology under which the price of Energy at each location in the NYS Transmission System is equivalent to the cost to supply the next increment of Load at that location (i.e., the short-run marginal cost). The short-run marginal cost takes Generation Bid Prices and the physical aspects of the NYS Transmission System into account. The short-run marginal cost also considers the impact of Out-of-Merit Generation (as measured by its Bid Price) resulting from the Congestion and Marginal Losses occurring on the NYS Transmission System which are associated with supplying an increment of Load. The term LBMP also means the price of Energy bought or sold in the LBMP Markets at a specific location.

2.98 Locational Installed Capacity Requirement

A determination of the ISO of that portion of the state-wide Installed Capacity requirement that must be electrically located within a Locality in order to ensure that sufficient Energy and Capacity are available in that Locality and that appropriate reliability criteria are met.

2.99 Lost Opportunity Cost

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

2.100 Major Emergency State

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

2.101 Marginal Losses

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

2.102 Marginal Losses Component

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

2.103 Market Participant

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

2.104 Market Services

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

2.105 Member Systems

The eight Transmission Owners that comprise the membership of the New York Power Pool.

2.106 Minimum Generation and Start-Up Bid

The payment required by a Supplier to bring a Generator to, and operate at, its minimum safe and stable operating level.

2.107 Modified Wheeling Agreement ("MWA")

A Transmission Agreement in existence, as amended, between Transmission Owners, that is associated with existing Generators or power supply contracts, that will be modified effective upon LBMP implementation. The terms and conditions of the MWA will remain the same as the original agreement, except as noted in the ISO OATT.

2.108 NERC

The North American Electric Reliability Council.

2.109 Network Integration Transmission Service

The Transmission Service provided under Part III of the Tariff.

2.110 New York Control Area ("NYCA")

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

2.111 New York Power Pool ("NYPP")

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

2.112 New York State Power System ("NYS Power System")

All facilities of the NYS Transmission System, and all those Generators located within the NYCA or outside the NYCA, some of which may from time-to-time be subject to operational control by the ISO.

2.113 New York State Reliability Council ("NYSRC")

An organization established by agreement among the Member Systems to promote and maintain the reliability of the NYS Power System.

2.114 New York State Reliability Council Agreement ("NYSRC Agreement")

The agreement which established the NYSRC.

2.115 New York State Transmission System ("NYS Transmission System")

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

2.116 Non-Firm-Point-To-Point Transmission Service

Point-To-Point Transmission Service under the Tariff for which a Customer is not willing to pay Congestion. Such service is available absent constraint under Part II of this Tariff. Non-Firm-Point-To-Point Transmission Service is available on a stand-alone basis for individual one-hour periods not to exceed twenty-four (24) consecutive hours.

2.117 Non-Utility Generator ("NUG ," "Independent Power Producer " or "IPP ")

Any entity that owns or operates an electric generating facility that is not included in an electric utility's rate base. This term includes, but is not limited to, cogenerators and small power producers and all other non-utility electricity producers, such as exempt wholesale generators that sell electricity.

2.118 Normal State

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

2.119 NPCC

The Northeast Power Coordinating Council.

2.120 NRC

The Nuclear Regulatory Commission or any successor thereto.

2.121 NYPA

The Power Authority of the State of New York.

2.122 NYPA Tax-Exempt Bonds

Obligations of the New York Power Authority, the interest on which is not included in gross income under the Internal Revenue Code.

2.123 Off-Dispatch

A Dispatchable Generator or Load that is not capable of responding to computer-issued ISO instructions but is capable of responding to ISO orders relayed by telephone.

2.124 Off-Peak

The hours between 11 p.m. and 7 a.m., prevailing Eastern Time, Monday through Friday, and all day Saturday and Sunday, and NERC-defined holidays, or as otherwise decided by ISO.

2.125 On-Dispatch

A Dispatchable Generator or Load that is capable of responding to computer-issued ISO instructions.

2.126 On-Peak

The hours between 7 a.m. and 11 p.m. inclusive, prevailing Eastern Time, Monday through Friday, except for NERC-defined holidays, or as otherwise decided by the ISO.

2.127 Open Access Same-Time Information System ("OASIS")

The information system and standards of conduct contained in Part 37 of the Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS.

2.128 Operating Capacity

Capacity that is readily converted to Energy and is measured in MW.

2.129 Operating Reserves

Generator Capacity that is available to supply Energy, or Interruptible Load Resources that are available to Curtail Energy usage, in the event of Contingency conditions, which meet the requirements of the ISO. Operating Reserves include spinning reserves, non-synchronized 10-minute reserves, and 30-minute reserves.

2.130 Operating Study Power Flow

A Power Flow analysis that is performed at least once before each Capability Period that is used to determine each Interface Transfer Capability for the Capability Period (See Attachment M to the ISO OATT).

2.131 Operational Control

Directing the operation of the Transmission Facilities Under ISO Operational Control to maintain these facilities in a reliable state, as defined by the Reliability Rules. The ISO shall approve operational decisions concerning these facilities, made by each Transmission Owner before the Transmission Owner implements those decisions. In accordance with ISO Procedures, the ISO shall direct each Transmission Owner to take certain actions to restore the system to the Normal State. Operational Control includes security monitoring, adjustment of generation and transmission resources, coordination and approval of changes in transmission status for maintenance, determination of changes in transmission status for reliability, coordination with other Control Areas, voltage reductions and Load Shedding, except that each Transmission Owner continues to physically operate and maintain its facilities.

2.132 Optimal Power Flow ("OPF")

The Power Flow analysis that is performed during the administration of the Centralized TCC Auction to determine the most efficient simultaneously feasible allocation of TCCs to Bidders (See Attachment M to the ISO OATT).

2.133 Order Nos. 888 et seq.

The Final Rule entitled Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, issued by the Commission on April 24, 1996, in Docket Nos. RM95-8-000 and RM94-7-001, as modified on rehearing, or upon appeal.

(See FERC Stats. & Regs. [Regs. Preambles January 1991- June 1996] ¶ 31,036 (1996) (“Order No. 888"), on reh’g, III FERC Stats. & Regs. ¶ 31,048 (1997) (“Order No. 888-A”), on reh’g, 81 FERC ¶ 61,248 (1997) (“Order No. 888-B”), order on reh’g, 82 FERC ¶ 61,046 (1998) (“Order No. 888-C”)).

2.134 Order Nos. 889 et seq.

The Final Rule entitled Open Access Same-Time Information System (formerly Real-Time Information Networks) and Standards of Conduct, issued by the Commission on April 24, 1996, in Docket No. RM95-9-000, as modified on rehearing, or upon appeal. (See FERC Stats. & Regs. [Regs. Preambles 1991-1996] ¶ 31,035 (1996) (“Order No. 889"), on reh’g, III FERC Stats. & Regs. ¶ 31,049 (1997) (“Order No. 889-A”), on reh’g, 81 FERC ¶ 61,253 (1997) (“Order No. 889-B”)).

2.135 Out-of-Merit Generation

Generators producing at a different level of output than they would produce in a dispatch to meet Load which was not security constrained. Out-of-Merit Generation occurs to maintain system reliability or to provide Ancillary Services.

2.136 Performance Index

An index, described in ISO Procedures, that tracks a Generator’s response to AGC signals from the ISO.

2.137 Performance Tracking System

A system designed to provide quantitative comparisons of actual values versus expected and forecasted values for Generators and Loads. This system will be used by the

ISO to measure compliance with criteria associated with the provision of Regulation and Frequency Response Service.

2.138 Point to Point Transmission Service

The reservation and transmission of Capacity and Energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under Part II of the Tariff.

2.139 Point(s) of Injection ("POI" or "Point of Receipt")

The point(s) on the NYS Transmission System where Energy, Capacity and Ancillary Services will be made available to the ISO by the delivering party under the ISO OATT or the ISO Services Tariff. The Point(s) of Injection shall be specified in the Service Agreement.

2.140 Point(s) of Withdrawal ("POW" or "Point of Delivery")

The point(s) on the NYS Transmission System where Energy, Capacity and Ancillary Services will be made available to the receiving party under the ISO OATT or the ISO Services Tariff. The Point(s) of Withdrawal shall be specified in the Service Agreement.

2.141 Pool Control Error ("PCE")

The difference between the actual and scheduled interchange with other Control Areas, adjusted for frequency bias.

2.142 Post Contingency

Conditions existing on a system immediately following a Contingency.

2.143 Power Exchange ("PE")

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

2.144Power Factor

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

2.145 Power Factor Criteria

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

2.146 Power Flow

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

2.147 Primary Holder

A Primary Holder of each TCC is the Primary Owner of that TCC or the party that purchased that TCC at the close of the Centralized TCC Auction. With respect to each TCC, a Primary Holder must be: (1) a Customer that has purchased the TCC in the Centralized TCC Auction, and that has not resold in that same Auction; (2) a Customer that has purchased the TCC in a Direct Sale with another Customer; (3) the Primary Owner who has retained the TCC and did not sell it through the Auction; or (4) Primary Owners of the TCC that allocated the TCC to certain customers or sold it in the Secondary Market or sold through a Direct Sale to an entity other than a Customer. The ISO settles Congestion Rents pursuant to Attachment J to the ISO OATT with the Primary of each TCC.

2.148 Primary Owner

The Primary Owner of each TCC is the Transmission owner or other Customer that has acquired the TCC through conversion of rights under an Existing Transmission Agreement to Grandfathered TCCs (in accordance with Attachment G) or the Transmission Owner that acquired the TCC through the ISO's allocation of Residual TCCs (in accordance with Attachment K and M). The ISO distributes Centralized TCC Auction revenues to Primary Owners (in accordance with Attachments K and M to the ISO OATT).

2.149 Proxy Generator Bus

A Generator bus located outside the NYCA that is selected by the ISO to represent a typical bus in an adjacent Control Area and for which LBMP prices are calculated.

2.150 PSC

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

2.151 PSL

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

2.152 Reactive Power (MVAr)

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

2.153 Real Power Losses

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

2.154 Real-Time LBMP

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

2.155 Real-Time Market

The ISO Administered Market resulting from the operation of the Security Constrained Dispatch (“SCD”).

2.156 Reduction or Reduce

The partial or complete reduction in non-Firm Transmission Service as a result of transmission Congestion (either anticipated or actual).

2.157 Reference Bus

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

2.158 Reliability Rules

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

2.159 Required System Capability

Generation capability required to meet an LSE's peak Load plus Installed Capacity Reserve obligation as defined in the Reliability Rules.

2.160 Residual TCCs

TCCs converted from RTC, each designated from a Point of Injection to a Point of Withdrawal. Residual TCCs are: (1) estimated prior to the Centralized TCC Auction, and allocated among the Transmission Owners utilizing the Interface MW-Mile Methodology; (2) determined during the Centralized TCC Auction that are in addition to the amount estimated before the Auction, and are not allocated but are offered for sale in the Auction; and (3) determined after each Grandfathered TCC and Grandfathered Right expire and the associated capacity is released to the ISO for sale and are not allocated but are offered for sale in the Auction. The Auction revenues and Excess Congestion Rent revenues associated with Residual TCCs that are not allocated to Transmission Owners by the ISO shall be allocated utilizing the Interface MW-Mile Methodology (See Attachments K and M to the ISO OATT).

2.161 Safe Operations

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

2.162 SCUC

Security Constrained Unit Commitment, described in Section 4.9 of the Tariff.

2.163 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.

2.164 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.

2.165 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.

2.166 Security Constrained Dispatch ("SCD")

The allocation of Load to Generators by the ISO through the operation of a computer algorithm which continuously calculates individual Generator loading at minimum Bid cost, balancing Load and scheduled interchange with Generation while meeting all Reliability Rules and Generator performance Constraints consistent with the terms of the ISO Services Tariff

2.167 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.

2.168 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.

2.169 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.

2.170 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.

2.171 Settlement

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

2.172 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.

2.173 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.

2.174 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.

2.175 Stranded Investment Recovery Charge

A charge established by a Transmission Owner to recover Strandable Costs.

2.176 Supplemental Resource Evaluation ("SRE")

A determination of the least cost selection of additional generators, which are to be committed, to meet changed conditions that may cause the original system dispatch to be inadequate to meet Load and/or reliability requirements.

2.177 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.

2.178 Third Party Transmission Wheeling Agreements ("Third Party TWA's")

A Transmission Wheeling Agreement, as amended, between Transmission Owner or between a Transmission Owner and an entity that is not a Transmission Owner associated with the purchase (or sale) of Energy, Capacity, and/or Ancillary Services for the benefit of an entity that is not a Transmission Owner. These agreements are listed in Table 1 of Attachment L to the ISO OATT.

2.179 Total Transfer Capability ("TTC")

The amount of electric power that can be transferred over the interconnected transmission network in a reliable manner.

2.180 Transaction

The purchase and/or sale of Energy or Capacity, or the sale of Ancillary Services.

2.181 Transfer Capability

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

2.182 Transmission Congestion Contract ("TCCs")

The right to collect or obligation to pay Congestion Rents associated with a single MW of transmission between a specified POI and POW. TCCs are financial instruments that enable Energy buyers and sellers to hedge fluctuations in the price of transmission.

2.183 Transmission Customer

Any entity (or its designated agent) that receives Transmission Service pursuant to a Service Agreement and the terms of the ISO OATT.

2.184 Transmission District

The geographic area served by the Investor-Owned Transmission Owners and LIPA, as well as the customers directly interconnected with the transmission facilities of the Power Authority of the State of New York.

2.185 Transmission Facilities Under ISO Operational Control

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

2.186 Transmission Facilities Requiring ISO Notification

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

2.187 Transmission Owner

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

2.188 Transmission Owner's Monthly Transmission System Peak

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

2.189 Transmission Reliability Margin ("TRM")

The amount of TTC reserved by the ISO to ensure the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions.

2.190 Transmission Service

Point-To-Point Network Integration or Retail Access Transmission Service provided under the ISO OATT.

2.191 Transmission Service Charge ("TSC")

A charge designed to ensure recovery of the embedded cost of a Transmission Owner's transmission system.

2.192 Transmission System

The facilities operated by the ISO that are used to provide Transmission Services under the ISO OATT.

2.193 Transmission Usage Charge ("TUC")

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

2.194 Transmission Wheeling Agreement ("TWA")

The Agreements listed in Table 1 of Attachment L to the ISO OATT governing the use of specific or designated transmission facilities that are owned, controlled or operated by an entity for the transmission of Energy in interstate commerce.

2.195 Wheels Through

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

2.196 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.

ARTICLE 3

TERM AND EFFECTIVENESS

3.1 Effectiveness

The ISO Services Tariff shall become effective on the latest of: (i) Commission approval of: (a) the ISO OATT, (b) the ISO Services Tariff, (c) the ISO Agreement, (d) the NYSRC Agreement, (e) the ISO/NYSRC Agreement, and (f) the ISO/TO Agreement (collectively, the "ISO Tariffs" and "ISO Related Agreements"); (ii) the date on which both the Commission and the PSC grant all necessary approvals to the Transmission Owners to transfer Operational Control of any facilities to the ISO or otherwise dispose of any of their property, including, without limitation, those approvals required under Section 70 of the New York Public Service Law ("PSL") and Section 203 of the Federal Power Act ("FPA"); (iii) the last date that any other approval or authorization is received, to the extent such additional approval or authorization is necessary; (iv) execution of the ISO Related Agreements; or (v) such later date specified by the Commission.

3.2 Term and Termination

The ISO Services Tariff shall remain in effect until: (i) canceled by the ISO upon sixty (60) days prior written notice in accordance with applicable Commission regulations; or (ii) the effective date of any law, order, rule, regulation, or determination of a body of competent jurisdiction requiring termination or a material modification of the ISO Services Tariff and/or the Service Agreements executed pursuant to the terms of the Tariff (See Attachment A) that would be inconsistent with any material term or provision of the ISO/TO Agreement. Any Customer may withdraw from the Tariff on thirty (30) days prior notice to the ISO; provided, however, that an LSE is required to be a Customer and comply with applicable requirements of the Tariff as long as it continues to serve Load in the NYCA.

3.3 Regulations

The ISO Services Tariff and any related Service Agreement are made subject to all applicable federal, state and local laws, regulations and orders.

3.4 Access to Complete and Accurate Data

Customers under the Tariff shall provide to the ISO such information and data as the ISO reasonably deems necessary in order to perform its functions and fulfill its responsibilities under the Tariff and in accordance with the ISO Market Power Monitoring Program. Such information will be provided on a timely basis and in the formats prescribed in the ISO Procedures. The ISO shall establish metering specifications and standards for all metering that is used as a data source by the ISO (See Article 13). Customers shall install and maintain such metering at their own expense and deliver data to the ISO without charge.

3.5 ISO Procedures

The ISO shall develop, and modify as appropriate, procedures for the efficient and non-discriminatory operation of the ISO Administered Markets and for the safe and reliable operation of the NYCA in accordance with the terms and conditions of the Tariff. All such procedures must be consistent with Good Utility Practice. Whenever requested by the ISO, each LSE shall provide the ISO with a forecast of the Loads for which it is responsible for the particular time period designated by the ISO. Customers shall inform the ISO, in accordance with the ISO Procedures, of the Availability of Generators within the NYCA subject to a Customer’s control by Energy contract, ownership or otherwise. Additionally, the Transmission Owners will provide megawatt, megavar, voltage readings, transmission system data (facility ratings and impedance data), and maintenance schedules for all Transmission Facilities Under ISO Operational Control. For Transmission Facilities Requiring ISO Notification, the Transmission Owners shall inform the ISO of all changes in the status of the designated transmission facilities. Suppliers will provide data on Generator status and output including maintenance schedules, Generator scheduled return dates, (inclusive of return to service from maintenance, forced outages or partial unit outages that resulted in a significant reduction in a generating unit's ability to produce Energy in any hour), and Generator machine data, in accordance with the ISO Procedures. These data shall also include Generator Incremental/Decremental Bids, operating limits, response rates, megawatt, megavar, and voltage readings.

3.6 Survival

Upon termination, expiration or cancellation of the ISO Services Tariff or any related Service Agreement, in accordance with their terms, the provisions of the Tariff, and any Service Agreement, shall remain in effect to the extent necessary to permit the conclusion of: (i) transactions previously initiated by the ISO hereunder; and (ii) billing, payment and accounting with respect to all matters arising hereunder or pursuant to a Service Agreement. Additionally, any provisions of the ISO Services Tariff or a Service Agreement which expressly survive termination or cancellation of the ISO Services Agreement or Service Tariff shall remain in effect in accordance with those provisions.

ARTICLE 4

MARKET SERVICES: RIGHTS AND OBLIGATIONS

4.1 Market Services

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

4.2 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, sells or purchases Capacity, or provides Ancillary Services in the ISO Administered Markets utilizes Market Services and must take service as a Customer under the Tariff.

4.3 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 and Ancillary Services by Suppliers for use by the ISO and the posting of Locational Based Marginal Prices (“LBMP”) and schedules for accepted Bids for Energy and Ancillary Services. 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.

4.4 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.

4.5 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.

4.6 Load Forecasts, Bids and Bilateral Schedules

By 5 a.m. on the day prior to the Dispatch Day: (i) All LSEs serving Load in the NYCA shall provide the ISO with Day-Ahead and seven (7) day Load forecasts; and (ii) LSEs and Suppliers who participate in the Day-Ahead Market shall provide the ISO with:

1. Bids to supply Energy and/or Ancillary Services from Generators;
2. Requests for Bilateral Transaction schedules; and
3. Bids to purchase Energy in the Day-Ahead Market.

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

Load Forecasts - The Load forecast shall indicate the predicted level of Load in MW by Point of Withdrawal for each hour of the following seven (7) days.

Bids to Supply Energy and/or Ancillary Services from Suppliers - Bids from Suppliers shall identify the Capacity, in MW, available for commitment in the Day-Ahead Market (for every hour of the Dispatch Day) and the price(s) at which the Supplier will voluntarily enter into dispatch commitments. The Bids shall identify the resource as Dispatchable (On-Dispatch or Off-Dispatch) or non-Dispatchable and will identify the Ancillary Services that are available from the resource. The Bids may separately identify Minimum Generation and Start-Up Bids and variable Energy price Bids.

Bilateral Transaction Schedules - Bilateral Transaction schedules shall identify hourly Transaction quantities (in MW) by Point of Injection and Point of Withdrawal and provide other information (as described in Attachment D).

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

4.7 ISO Responsibility to Establish a State-wide Load Forecast

By 6 a.m. on the day prior to the Dispatch Day, the ISO will verify the individual Load forecasts from the LSEs. Should the ISO determine that individual Load forecasts are inconsistent with the ISO's forecast, the ISO will evaluate the discrepancies between them.

By 8 a.m., the ISO will develop and publish its statewide Load forecast on the OASIS. The ISO will use this forecast to perform the SCUC for the Dispatch Day.

4.8 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 LSEs serving Load in the NYCA must comply with the Installed Capacity requirements set forth in Article 5 of the 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.

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

4.9 Security Constrained Unit Commitment ("SCUC")

Subject to ISO Procedures and Good Utility Practice, the ISO will develop a SCUC schedule over the Dispatch Day using a computer algorithm which simultaneously minimizes the total Bid Production Cost of: (i) supplying power to satisfy accepted purchasers' Bids to buy Energy from the Day-Ahead Market; (ii) providing sufficient Ancillary Services to support Energy purchased from the Day-Ahead Market; (iii) committing sufficient Capacity to meet the ISO's Load forecast and provide associated Ancillary Services; and (iv) meeting Bilateral Transaction schedules submitted Day-Ahead. The schedule will include commitment of sufficient Generators and/or Interruptible Load to provide for the safe and reliable operation of the NYS Power System. In cases in which the sum of all Bilateral Schedules and all Day-Ahead Market purchases to serve Load within the NYCA in the Day-Ahead schedule is less than the ISO's Day-Ahead forecast of Load, the ISO will commit resources in addition to the reserves it normally maintains to enable it to respond to contingencies. The purpose of these additional resources is to ensure that sufficient Capacity is available to the ISO in real-time to enable it to meet its Load forecast (including associated Ancillary Services). In addition to all Reliability Rules, the ISO shall consider the following information when developing the SCUC schedule: (i) Load forecasts provided to the ISO and adjusted as required by the ISO; (ii) Ancillary Service requirements as determined by the ISO; (iii) Bilateral Transaction schedules; (iv) price Bids and operating Constraints submitted for Generator or Demand Side Resources; (v) price Bids for Ancillary Services; (vi) Decremental Bids for Bilateral Transactions; (vii) Ancillary Services in support of Bilateral Transactions; and (viii) Bids to purchase Energy from the Day-Ahead Market. The SCUC schedule shall list the twenty-four (24) hourly injections for: (a) each Generator or Demand Side Resource whose Bid the ISO accepts for the following Dispatch Day; and (b) each Bilateral Transaction scheduled Day-Ahead.

In the development of its SCUC schedule, the ISO may commit and decommit Generators based upon any flexible Bids, including Minimum Generation and Start-Up Bids, Energy, and Incremental Bids and Decremental Bids received by the ISO.

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

4.10 Reliability Forecast

In the SCUC program, system operation shall be optimized based on Bids over the Dispatch Day. However, to preserve system reliability, the ISO must ensure that there will be sufficient resources available to meet forecasted Load and reserve requirements over the seven (7)-day period that begins with the next Dispatch Day. The ISO will perform a Supplemental Resource Evaluation ("SRE") for days two (2) through seven (7) of the commitment cycle. If it is determined that a long start-up time Generator is needed for reliability, the ISO shall accept a Bid from the Generator and the Generator will begin its start-up sequence. During each day of the start-up sequence, the ISO will perform an SRE to determine if long start-up time Generators will still be needed as previously forecasted. If the Generator is still needed, it will continue to accrue start-up cost payments on a linear basis. If at any time it is determined that the Generator will not be needed as previously forecasted, the ISO shall order the Generator to abort its start-up sequence, and its start-up payment entitlement will cease at that point.

The ISO will commit to long start-up time Generators to preserve reliability. However, the ISO will not commit resources with long start-up times to reduce the cost of meeting Loads that it expects to occur in days following the next Dispatch Day. Supplemental payments to these Generators, if necessary, will be determined pursuant to the provisions of Attachment C and will be recovered by the ISO under Rate Schedule 1 of the ISO OATT.

The ISO shall perform the SRE as follows: (1) The ISO shall develop a forecast of daily system peak Load for days two (2) through seven (7) in this seven (7)-day period (using LSE forecast data, where appropriate) and add the appropriate reserve margin; (2) the ISO shall then forecast its available Generators for the day in question by summing the Operating Capacity for all Generators currently in operation that are available for the commitment cycle, the Operating Capacity of all other Generators capable of starting on subsequent days to be available on the day in question, and an estimate of the net imports from External Bilateral Transactions; (3) if the forecasted peak Load plus reserves exceeds the ISO's forecast of available Generators for the day in question, then the ISO shall commit additional Generators capable of starting prior to the day in question (e.g., start-up period of two (2) days when looking at day three (3)) to assure system reliability; (4) in choosing among Generators with comparable start-up periods, the ISO shall schedule Generators to minimize the start-up and minimum Generation Bid costs of meeting forecasted peak Load plus Ancillary Services consistent with the Reliability Rules; (5) In determining the appropriate reserve margin for days two (2) through seven (7), the ISO will supplement the normal reserve requirements to allow for forced outages of the short start-up period units (e.g., gas turbines) assumed to be operating at maximum output in the unit commitment analysis for reliability.

The bidding requirements and the Bid tables in Attachment D indicate that Energy Bids are to be provided for days one (1) through seven (7). Energy Bids are binding for day one (1) only for units in operation or with start-up periods less than one (1) day. Minimum generation cost Bids for Generators with start-up periods greater than one (1) day will be binding only for units that are committed by the ISO and only for the first day in which those units could produce Energy given their start-up periods. For example, minimum generation cost Bids for a Generator with a start-up period of two (2) days would be binding only for day three (3) because, if that unit begins to start up at any time during day one (1), it would begin to produce Energy forty-eight (48) hours later on day three (3). Similarly, the minimum generation cost Bids for a Generator with a start-up period of three (3) days would be binding only for day four (4).

4.11 Post the Day-Ahead Schedule

By 11 a.m. on the day prior to the Dispatch Day, the ISO shall close the Day-Ahead scheduling process and post on the Bid/Post System the Day-Ahead schedule for each entity that submits a Bid or Bilateral Transaction schedule. Schedules for Energy consumption and Generator output shall be considered proprietary, with the posting only visible to the appropriate scheduling Customer and Transmission Owners subject to the applicable Code of Conduct (See Attachment F to the ISO OATT). The ISO will post on the OASIS the statewide aggregate resources (Day-Ahead Energy schedules and total operating capability forecast) and Load (Day-Ahead scheduled and forecast) for each Load Zone, and the Day-Ahead LBMP prices (including the Congestion Component and the Marginal Losses Component) for each Load Zone in each hour of the upcoming Dispatch Day. The ISO shall conduct the Day-Ahead Settlement based upon the Day-Ahead schedule determined in accordance with this Section. The ISO will provide the Transmission Owner with the Load forecast (for seven (7) days) as well as the ISO security evaluation data to enable local area reliability to be assessed. A Transmission Owner may request commitment of additional Generators (including specific output level(s)) if it determines that additional generation is needed to ensure local area reliability in accordance with the Local Reliability Rules. The ISO will use SRE to fulfill a Transmission Owner's request for additional units.

4.12 Commitment for Local Reliability

Generating units committed by the ISO for service to ensure local reliability will recover startup and minimum generation costs not recovered in the Dispatch Day. Payment for such costs shall be determined pursuant to the provisions of Attachment C. With the exception of Storm Watch, such payments shall be recovered by the ISO from the local customers for whose benefit the Generation was committed in accordance with Rate Schedule 1 of the ISO OATT. Payments made by the ISO to those Generators shall be in accordance with Attachment C.

4.13 In-Day Scheduling Changes

After the Day-Ahead schedule is published, the ISO shall evaluate any events, including, but not limited to, the loss of significant Generators or transmission facilities that may cause the system dispatch to be inadequate to meet the requirements established in the Reliability Rules.

The ISO shall modify, as necessary, the Day-Ahead commitment schedules via SRE to achieve a reliable next-day schedule while minimizing total Bid Production Cost over the remainder of the day to meet Load scheduled Day-Ahead. The ISO may use the following resources in order to prevent or address an Emergency: (i) Bids submitted to the ISO that were not previously accepted but were designated by the bidder as continuing to be available; (ii) new Bids from all Suppliers, including neighboring systems; and (iii) cancellation of/or rescheduling of transmission facility maintenance outages when possible. Actions taken by the ISO in performing supplemental commitments will not change any financial commitments that resulted from the Day-Ahead SCUC.

Pursuant to ISO Procedures, the ISO shall Curtail deliveries to a Customer purchasing Energy in the Day-Ahead Market to serve Load located outside the NYCA, if necessary to maintain appropriate reliability criteria for the NYCA or to avoid Load Shedding in the NYCA.

4.14 Balancing Market Evaluation (Hour-Ahead)

After the Day-Ahead schedule is published, and up to ninety (90) minutes prior to each dispatch hour, Customers may: (i) submit additional Bids to the ISO for Energy from (a) Generators or other resources that are Dispatchable within five (5) minutes and that can be included in, and respond to, the ISO's SCD program and (b) Generators or other resources that provide fixed block Energy (non-Dispatchable) Bids available for the next hour; (ii) lower their Bid Price for Energy from Generators committed by the ISO in the Day-Ahead Market; (iii) change their Bid Price for additional Energy from Generators that were committed by the

ISO in the Day-Ahead Market; (iv) propose new Bilateral Transactions; and (v) submit Bids to purchase Energy from the Real-Time Market. The Bids submitted up to ninety (90) minutes before the dispatch hour shall be referred to as Hour-Ahead Bids. The ISO will use the Balancing Market Evaluation ("BME") to determine which Transactions, including External Transactions affecting the NYCA, are permitted in each hour. The ISO shall use the BME ninety (90) minutes before each dispatch hour to determine schedules for the Real-Time Market and Bilateral Transactions including Exports, Imports and Wheels Through. In developing these schedules, the BME will consider updated Load forecasts and evaluate the impact on reliability of the proposed schedules and commitments. The BME will adjust firm Bilateral Transaction schedules based on Incremental Bids and Decremental Bids and all Generator schedules, based on their Bids, to maintain reliability. The BME will not determine any prices but will schedule on a least total Bid Production Cost basis. Minimum run-time constraints will be honored by BME only until midnight of the Dispatch Day.

4.15 ISO Real-Time Dispatch

The ISO shall dispatch the NYS Power System consistent with the Bids that are submitted by Suppliers and accepted by the ISO, while satisfying the actual system Load. The ISO shall use Day-Ahead and Hour-Ahead Bids and shall accommodate Bilateral Transaction schedules and schedule changes to the maximum extent possible consistent with reliability and the Decremental Bids of Bilateral Transaction parties. The ISO shall run a SCD nominally every five (5) minutes to minimize the total Bid Production Costs of meeting the system Load and maintaining scheduled interchanges with adjacent Control Areas over the next SCD interval. Bid Production Costs, for this purpose, will be calculated using accepted Day-Ahead and Hour-Ahead Bids submitted into the Real-Time Market. This dispatch may cause the schedules of Generators providing Energy under Bilateral Transaction schedules to be modified, depending upon the Decremental Bids submitted (or assigned) in association with these schedules.

4.16 Day-Ahead LBMP Market Transactions

The ISO shall calculate the Day-Ahead LBMPs for each Load Zone and at each Generator bus as described in Attachment B. Each Supplier that bids a Generator into the ISO Day-Ahead Market and is scheduled in the SCUC to sell Energy in the Day-Ahead Market will be paid the product of: (a) the Day-Ahead hourly LBMP at the applicable Generator bus; and (b) the hourly Energy schedule. Each LSE that bids into the ISO Day-Ahead Market and has a schedule accepted by the ISO to purchase Energy in the Day-Ahead Market will pay the product of: (a) the Day-Ahead hourly Zonal LBMP at each Point of Withdrawal; and (b) the scheduled Energy at each Point of Withdrawal. The ISO shall publish the Day-Ahead Settlement Load Zone LBMPs for each hour in the scheduling horizon (nominally twenty-four (24) hours). The ISO shall then close the Day-Ahead Settlement.

4.17 Real-Time LBMPs

The ISO shall calculate Real-Time LBMPs at each Generator bus based on data generated by the SCD program and for each Load Zone in accordance with the procedures set forth in Attachment B.

4.18 Real-Time Settlement

Transmission Customers taking service under the Tariff, shall be subject to the Real-Time Market Settlement. 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 Settlements for injections by resources supplying Regulation service follow the rules which are described in Rate Schedule 3.)

A. Settlement When Actual Energy Withdrawals Exceed Scheduled Energy Withdrawals

When the Actual Energy Withdrawals by a Customer over an SCD interval exceed the Energy withdrawals scheduled over that SCD interval, the ISO shall charge the Real-Time LBMP for Energy equal to the product of: (a) the Real-Time LBMP calculated in that SCD interval for each applicable Load Zone; and (b) the difference between the Actual Energy Withdrawals and the scheduled Energy withdrawals at that Load Zone.

B. Settlement When Actual Energy Injections are Less Than Scheduled Energy Injections

When the actual Energy injections from a Generator over an SCD interval is less than the Energy injections scheduled over that SCD interval, the Supplier shall pay for the Energy imbalance in a charge equal to the product of: (a) the Real-Time LBMP calculated in that SCD interval for the applicable Generator bus; and (b) the difference between the scheduled Energy injections and the lesser of: (i) the actual Energy injections at that bus; or (ii) the SCD Base Point Signals sent to the Supplier in that SCD interval.

C. Settlement When Actual Energy Withdrawals are Less Than Scheduled Energy Withdrawals

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 SCD interval for each applicable Load Zone; and (b) the difference between the scheduled Energy withdrawals and the Actual Energy Withdrawals at that Load Zone.

D. Settlement When Actual Energy Injections Exceed Scheduled Energy Injections

When actual Energy injections from a Generator over an SCD interval exceeds the Energy injections scheduled the Supplier shall be paid the product of: (1) the Real-Time LBMP calculated in that SCD interval for the applicable Generator bus and the difference between the scheduled Energy injections and the actual Energy injections up to the SCD Base Point Signals sent to that Supplier by the ISO; unless payment that the Supplier would receive for such injections would be negative (i.e., unless the LBMP calculated in that SCD interval at the applicable Generator's bus is negative). Suppliers shall not be compensated for Energy in excess of the SCD Base Point Signals communicated by the ISO except when the ISO initiates a reserve pick-up, as provided for in the ISO Procedures, or a Transmission Owner initiates a reserve pick-up in accordance with a Reliability Rule, including a Local Reliability Rule. When there is no reserve pick-up or when there is a reserve pick-up but a Supplier is not located in the area affected by the reserve pick-up, that Supplier shall not be compensated for Energy in excess of the SCD Base Point Signal. The Supplier shall be paid based on the product of : (1) the Real-Time LBMP in that SCD interval for the applicable Generator bus; and (2) the difference between (a) the lesser of (i) the actual Energy injection or (ii) the SCD Base Point Signals sent to the Supplier in that interval, and (b) the scheduled Energy injection. When there is a reserve pick-up and a Supplier is located in the area affected by the pick-up, and the Supplier was either scheduled to operate as a result of the BME 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 SCD 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.

4.19 Payments to Suppliers for Regulation Service ("Regulation Service")

Suppliers of Regulation Service shall receive an Availability payment that is calculated as the product of: (a) the Regulation Market Clearing Price for regulating Capacity; (b) the time in hours or fraction thereof the Supplier is providing Regulation Service; and (c) the regulating Capacity in MW. The methodologies for determining the Regulation Market Clearing Price are set forth in Rate Schedule 3.

4.20 Payments to Suppliers of Reactive Supply and Voltage Support Service ("Voltage Support Service")

Suppliers of Voltage Support Service shall receive a Voltage Support Service payment in accordance with the criteria and formula in Rate Schedule 2.

4.21 Payments to Generators for Operating Reserves

Suppliers of each type of Operating Reserve will receive Availability payments for each MW of reserve that they provide as requested by the ISO, pursuant to Rate Schedule 4. Availability payments shall be determined separately for each of the three categories of Operating Reserves: spinning reserve, 10-minute non-synchronized reserve and 30-minute reserve. The ISO shall pay Suppliers of each category an Availability payment calculated as the product of: (a) the market clearing price for the applicable reserve; and (b) the MW to be provided by the Suppliers, as selected by the ISO, in the associated reserve category.

Additionally, Class A Units providing spinning reserves shall receive a payment whenever the ISO restricts the output of a Generator for the purpose of creating spinning reserve. The payment that any such provider receives in each SCD interval shall be calculated as the product of: (a) the MW of out-of-merit output reduction as dispatched by the ISO to provide spinning reserves, in that SCD interval; and (b) the maximum Lost Opportunity Cost incurred by any Generator providing spinning reserves in that SCD interval.

Additionally, providers of Operating Reserves shall receive a payment for Energy when the ISO requests Energy under a reserve activation. The Energy payment shall be calculated as the product of: (a) the Energy provided; and (b) the Real-Time Market LBMP.

4.22 Payments to Generators for Black Start Capability

Black Start Capability providers shall receive a payment for Black Start Capability as set forth in Rate Schedule 5.

4.23 Payments for Start-up and Minimum Generation Bids

The ISO shall determine, on a daily basis, if any Generator committed by the ISO in the Day-Ahead Market will not recover its Minimum Generation and Start-Up and Energy Bid Price through Day-Ahead LBMP and Day-Ahead Ancillary Services revenues. If a Generator's Minimum Generation and Start-Up Bid plus its net Energy Bid Price over the twenty-four (24) hour day exceeds its Day-Ahead LBMP revenue over the twenty-four (24) hour day, its Day-Ahead LBMP revenue may be augmented by a supplemental payment. However, the amount of the shortfall will be compared to the margin that the Generator receives from being scheduled to provide Ancillary Services that it can provide only if scheduled to operate. The Generator's Ancillary Service margin is equal to the revenue it receives for providing these Ancillary Services less its Bid to provide these services, if any. If, and only to the extent that, the shortfall exceeds these Ancillary Service margins, the Generator will receive a payment pursuant to the provisions of Attachment C. This process will be repeated separately for Dispatch-Day operation. Generators not committed by the

ISO to operate in a given Dispatch Day, but which continue to operate due to minimum run time Constraints, shall not receive such a supplemental payment.

Each Generator committed by the ISO in the Real-Time Market whose Real-Time LBMP payments for Energy produced are less than its Minimum Generation and Start-Up Bids to produce that Energy will be compensated by the ISO for the shortfall, in accordance with Attachment C. The ISO shall recover any supplemental payments to Generators through the Rate Schedule 1 charge under the ISO OATT.

ARTICLE 5

CONTROL AREA SERVICES: RIGHTS AND OBLIGATIONS

5.1 Control Area Services

The ISO will provide Control Area Services in accordance with the standards and criteria of NERC and NPCC and the NYSRC Reliability Rules and Good Utility Practice. The Control Area Services provided by the ISO include, but are not limited to, the following:

(a) Developing and implementing procedures to maintain the reliability of NYS Power System;

(b) Coordinating operations with other Control Area operators;

(c) Arranging for reserve sharing agreements with other ISOs and other Control Areas to enhance reliability during abnormal operating conditions;

(d) Coordinating the outage schedules for generating units within the NYCA to maintain system reliability;

(e) Committing adequate generation resources to ensure the reliability of the NYS Power System;

(f) Taking command and control of the NYCA resources during Emergency conditions and coordinating operations with Transmission Owners;

(g) Maintaining and Operating a central control center and performing the functions of the NERC security control center for the NYCA under Emergency operating conditions;

(h) Defining the Installed Capacity requirements for LSEs, inclusive of individual customers taking services directly from the ISO, within the NYCA;

(i) Determining Locational Installed Capacity requirements for LSE's to ensure the reliable operation of the NYCA;

(j) Administering of an Installed Capacity Market;

(k) Training the operating personnel of the ISO and Transmission Owner control rooms; and

(l) Administering the mandatory NERC reliability compliance process.

5.2 Independent System Operator Authority

The ISO will act as the Control Area operator, as defined by NERC, for the NYCA. The ISO will provide all Control Area Services in the NYCA. Control Area Services provided by the ISO will be in accordance with the terms of the ISO Services Tariff, the Reliability Rules, the ISO Related Agreements and Good Utility Practice. The ISO will interact with other Control Area operators as required to effect External Transactions pursuant to this Tariff and to ensure the effective and reliable coordination with the interconnected Control Areas. In acting as the Control Area operator, the ISO will be responsible for maintaining the safety and the short-term reliability of the NYCA and for the implementation of reliability standards promulgated by NERC and NPCC and for the Reliability Rules promulgated by the NYSRC. To be included within NYCA, a Market

Participant must meet the requirements of Section 5.6. Each Market Participant that (1) withdraws Energy to supply Load within the NYCA; or (2) provides installed Capacity to an LSE serving Load within the NYCA, benefits from the Control Area Services provided by the ISO and from the reliability achieved as a result of ISO Control Area Services and must take service as a Customer under the Tariff. A Market Participant that is not included within the NYCA may take service as a Customer under the Tariff, provided that it meets the requirements of Section 5.7.

5.3 Control Center Operation

The ISO will maintain and operate a control center in order to monitor the power flows on and across the NYCA, coordinate the flow of electricity within the NYCA, respond to Emergency situations, monitor power flows between the NYCA and neighboring Control Areas and maintain reliability.

5.3.1 Back-up Operation

The ISO shall develop Back-up Operation procedures that will carry out the intent and purposes of the ISO Services Tariff, to the extent practical, in circumstances under which the normal communications and computer systems of the ISO are not fully functional. Such procedures shall include testing requirements and training of the ISO staff, Transmission Owner staff, and Market Participants. If a communication or computer system malfunction results in the ISO's inability to operate the NYCA in accordance with the ISO Procedures or under approved testing procedures, the ISO will direct the Transmission Owners to assume the responsibility to operate their respective systems in accordance with Good Utility Practice to facilitate the operation of the NYCA in a safe and reliable manner ("Back-up Operation"). The Transmission Owners will continue to operate their respective systems until such time that the ISO is ready to resume control. During Back-up Operation, the Transmission Owner control centers will operate to maintain the Desired Net Interchange ("DNI") within each Transmission District. Generator Bid curves will be provided by the ISO to the individual Transmission Owners in order to permit dispatch by the Transmission Owners subject to the Transmission Owner Code of Conduct. Normal Day-Ahead Market and Real-Time Market operations may be halted, if required.

5.3.2 Market Participant and Transmission Customer Obligations

During Back-up Operation, Transmission Customers and other Market Participants shall comply with any and all instructions and orders issued by the ISO or the Transmission Owners.

5.3.3 Billing and Settlement

In the event that Back-up Operation is implemented, the billing and Settlement procedures contained in this Tariff shall apply to the extent they can be implemented under the Back-up Operation procedures. The ISO will follow specific billing and Settlement procedures developed by the ISO for use under these circumstances. The ISO shall gather necessary information, manually reconstruct the billing information as soon as practical, and submit invoices to Customers. The ISO shall be under no obligation to comply with the billing procedure time limits specified in Article 7. Neither the ISO nor the Owners shall be liable, under any circumstances, for any economic losses suffered by any Transmission

Customer, other Market Participant, or third party, resulting from the implementation by the ISO of Back-up Operation, or from compliance with orders issued by the ISO or Transmission Owners that were necessary to operate the NYCA in a safe and reliable manner. Such orders may include, without limitation, instructions to Generation facilities to increase or decrease output, and instructions to Load to reduce or interrupt service.

5.4 Operation Under Adverse Conditions

The ISO shall operate the NYS Power System during Adverse Conditions, including, but not limited to, thunder storms, hurricanes, tornadoes, solar magnetic flares and threat of terrorist activities, in accordance with the Reliability Rules, inclusive of Local Reliability Rules and related PSC orders. Consistent with such Reliability Rules, the ISO shall maintain reliability of the NYS Power System by directing the adjustment of the Generator output levels and controllable transmission devices in certain areas of the system to reduce power flows across transmission lines vulnerable to outages due to these Adverse Conditions, thereby reducing the likelihood of major power system disturbances.

The ISO shall have the sole authority to declare that Adverse Conditions are imminent or present and invoke the appropriate operating procedure(s) affecting the NYS Power System in response to those conditions. Activation of a procedure in compliance with a Local Reliability Rule shall involve a two (2) step process. The Transmission Owner directly involved with such Local Reliability Rule, such as Storm Watch, shall advise the ISO that Adverse Conditions are imminent or present and recommend to the ISO the activation of applicable procedures in support of that Local Reliability Rule. Consistent with the Local

Reliability Rule, the ISO shall declare the activation of the appropriate procedures. The Transmission Owner and the ISO shall coordinate the implementation of the applicable procedures to the extent that Transmission Facilities Under ISO Operational Control are impacted. Records pertaining to the activation of such procedures and the response in accordance with those procedures shall be maintained and made available upon request.

The Real-Time LBMPs shall be based on adjusted Generator levels set in response to activation of these procedures. Revenue shortfalls may occur if the redispatch of the system Curtails Energy scheduled Day-Ahead and more expensive Energy is dispatched subsequent to the Day-Ahead Settlement. These revenue shortfalls shall be recovered by the ISO through the Rate Schedule 1 charge under the ISO OATT.

5.5 Major Emergency State

In the event of, or in order to prevent, a Major Emergency State, Customers shall comply with all ISO Procedures and Reliability Rules applicable to a Major Emergency State.

5.6 Requirements For Inclusion Within The New York Control Area

To be included within the NYCA an entity must meet the following requirements:

(a) Its facilities must be included within the NYCA.

(b) It must accept and comply with NYCA standards with respect to system design, equipment ratings, operating practices and maintenance practices as set forth in the ISO Procedures so that sufficient electrical equipment control capability, information and communication are available to the ISO for planning and operation of the NYCA.

(c) Its facilities must be able to respond to command and control instructions from the ISO.

(d) It must have compatible operational communication mechanisms, maintained at its expense, to interact with the ISO and for internal requirements.

(e) It must ensure the continued compatibility of its local energy management system, system monitoring and telecommunications systems to satisfy the technical requirements of interacting with the ISO as the ISO directs the operation of the NYCA.

5.7 Requirements For Entities Not Located Within The New York Control Area

In order for an entity that is not included within the NYCA to take services under the Tariff, it must be contained, in whole or in part, within a separate Control Area that meets all of the requirements for a Control Area defined by NERC, NPCC and any succeeding organizations. An entity that is contained in a Control Area other than the NYCA may take services under the ISO Services Tariff for the purpose of engaging in Control Area to Control Area Capacity and Energy transactions with the ISO. In order for an entity not contained in the NYCA to take services under the ISO Services Tariff, an inter-Control Area agreement between the Control Area in which the entity is located and the ISO, that satisfies the reasonable requirements of both Control Area operators, must be in place.

5.8 Communication and Metering Requirements for Control Area Services

The ISO shall arrange for and maintain reliable communications and metering facilities between the ISO and the Transmission Owners in the NYCA and the Control Area operators of all neighboring interconnected Control Areas. Such facilities may consist of data circuits, voice lines, meters and other facilities deemed necessary by the ISO to maintain reliable communication links for the sole purpose of transmitting operations and reliability data and instructions. The ISO shall be responsible for the specification, installation and maintenance of the required facilities according to ISO Procedures. The costs incurred by the ISO to establish communications facilities between the ISO and a Security Coordinators of a neighboring Control Area shall be borne by the Control Area that requested the establishment of the communications facilities unless a different arrangement is agreed to by both Control Areas. The total cost of the communications facilities between the ISO and the Transmission Owners and the portion of the cost of inter-Control Area communication facilities assigned to the ISO shall be collected from all Customers in accordance with Rate Schedule 1 of the ISO Services Tariff. Transmission Owners with communications requirements which exceed those required by the ISO shall procure and maintain such additional facilities at their own expense.

Generators, Suppliers and Loads are required to exchange certain operating and reliability data with the ISO and the Transmission Owners' Control Centers in accordance with the ISO Agreement and the ISO/TO Agreement, applicable ISO operating and reliability requirements, and in conjunction with any requirements for interconnection with the Transmission Owner.

In addition, Suppliers wishing to participate in real-time dispatch or in the Regulation Service market must make provision to receive command and control information from the ISO. Those Generators or Suppliers currently providing this capability via a Transmission Owner may continue to do so. Those requiring installation of this capability must contract with the ISO or with the interconnected Transmission Owner and must comply with applicable ISO or Transmission Owner data and other technical requirements.

Suppliers with multiple units at a single location must maintain a consistent representation of the plant with the ISO with respect to aggregation of units for purposes of bidding. If an aggregate Bid is to be provided for a group of units and those units are participating in real-time dispatch or providing Regulation Service, then the ISO shall model those units as a group for purposes of dispatch, control and security modeling. The ISO will provide a single aggregate Base Point Signal and unit control error. If, however, the Supplier wishes to dispatch units individually, then it must configure both its bidding and data interfaces accordingly. Each Supplier must initially specify the configuration of the plant for purposes of bidding aggregation and must then maintain bidding and data interfaces consistent with that configuration. Similar modeling, control and bidding Constraints apply to an LSE that bids Load that is Dispatchable by the ISO.

5.9 LSE Installed Capacity Requirements - Transitional Arrangements

Through the 1999 Summer Capability Period, which ends October 31, 1999, Load Serving Entities will be required to satisfy Installed Capacity requirements under the existing New York Power Pool procedures (Billing Procedure No. 4). Transmission Owner settlement agreements approved by the PSC, or policies approved by NYPA or LIPA. For Installed Capacity requirements starting with the 1999-2000 Winter Capability Period, which starts November 1, 1999, the provisions of Section 5.10 will apply.

5.10 LSE Installed Capacity Requirements

All LSEs serving Load in the NYCA, whether through purchases in the ISO Administered Markets or Bilateral Transactions or any combination thereof, must comply with the Installed Capacity requirements set forth in this Tariff. The ISO shall calculate each LSE's annual Installed Capacity requirement in accordance with the total Installed Capacity requirement established by the NYSRC, including the location of Installed Capacity both internal and external to the NYCA.

5.10.1 NYCA Installed Capacity Requirement

The Installed Capacity requirement for the NYCA will be established by the NYSRC for the Capability Year beginning each May 1. The ISO will determine the amount of Installed Capacity that must be sited within the NYCA and the amount of Installed Capacity that may be procured from areas external to the NYCA, while meeting NYSRC Reliability Rules.

The ISO shall develop Generator Availability and capability standards, and criteria for Loads capable of disconnecting from the electrical system within a predetermined, and agreed upon, time limit.

The ISO shall establish minimum Generator Availability standards for each Generator Class, based on accepted standards and practices. Availability Standards in effect under the NYPP will remain in effect unless and until the ISO implements new Availability Standards.

Availability Standards will be developed by the ISO for new Generator Classes as new technologies are utilized in Generator design.

Each LSE will be required to meet its annual Installed Capacity requirement for the upcoming Capability Period. Load forecasts supplied by LSEs shall be in accordance with methodologies approved by the ISO.

The ISO shall calculate the Installed Capacity requirement for each LSE using a two-step procedure. First, an Installed Capacity requirement will be calculated for each Transmission District. Second, the Installed Capacity requirement for each Transmission District will then be allocated among all LSEs that serve Load in that Transmission District.

The Installed Capacity requirement for each winter-peaking Transmission District shall be (1 + X/100) times the Load in that Transmission District during that Transmission District's peak hour for that Winter Capability Period. (The peak hour is the hour in each Capability Period in which the Load in a Transmission District is the highest, and X is the reserve requirement percentage defined by the ISO that is applicable to each Transmission District.) During the subsequent Summer Capability Period, the Installed Capacity requirement for each winter-peaking Transmission District shall be the lower of either: (a) (X/100) times the Load in that Transmission District during its peak hour for the preceding Winter Capability Period; or (b) (3/2 X/100) times the Load in that Transmission District during its peak hour for that Summer Capability Period; plus (c) the Load in that Transmission District during its peak hour for that Capability Period (i.e., the summer reserve margin for that Transmission District is capped at 3/2 X percent of the summer peak hour Load).

The Installed Capacity requirement for each summer-peaking Transmission District for both Summer and Winter Capability Periods shall be (1 + X/100) times the Load in that Transmission District during that Transmission District's summer peak hour.

An adjusted peak Load will be determined for each LSE, for each Capability Period, and for each Transmission District in which that LSE serves Load. The adjusted peak Load will be equal to the greater of: (a) the amount of Energy consumed by that LSE's customers within that Transmission District during that Transmission District's peak hour for that Capability Period; or (b) the average amount of Energy consumed by that LSE's customers within that Transmission District over the duration of the Capability Period.

Each LSE's share of the Installed Capacity requirement for a Transmission District during a given Capability Period will be calculated by multiplying that Transmission District's Installed Capacity Requirement for that Capability Period by the ratio of that LSE's adjusted peak Load for that Transmission District and Capability Period to the sum of the adjusted peak Loads for all LSEs serving Load in that Transmission District in that Capability Period. Each LSE's total Installed Capacity requirement will be equal to the sum of its shares of the Installed Capacity requirements in the Transmission Districts in which it serves Load.

In cases in which a Load is served by different LSEs over the course of a Capability Period, item (a) in the above calculation of an LSEs adjusted peak Load will be modified. It will be replaced by the amount of Energy consumed by each Load within that Transmission District during that Transmission District's peak hour for that Capability Period, multiplied by the ratio of the amount of Energy consumed by that Load during that Capability Period to the total amount of Energy consumed by that Load in the Transmission District during the Capability Period. Thus, if 10MW of Load is transferred from LSE A to LSE B during a Capability Period such that LSE A and LSE B, respectively, supply 60% and 40% of that Load's Energy during the Capability Period, LSE A will have Installed Capacity responsibility for 6MW of Load and LSE B will have Installed Capacity responsibility for 4MW of Load. Both LSE A and LSE B must comply with Locational Installed Capacity requirements.

5.10.2 Locational Installed Capacity Requirements of LSEs

The ISO will determine the Locational Installed Capacity Requirements applicable to each LSE. In establishing Locational Installed Capacity Requirements, the ISO will take into account all relevant considerations, including the total Installed Capacity requirements, the NYS Power System transmission Interface Transfer Capability, and the Reliability Rules.

Any Locational Installed Capacity Requirements operative at the commencement of ISO operations adopted by LIPA or under settlement agreements approved by the PSC shall continue in effect in accordance with their terms unless and until the ISO implements new or modified Locational Installed Capacity Requirements.

Each LSE will secure at least the required amount of Installed Capacity for the upcoming Capability Period from resources consistent with the locational requirements established by the ISO.

Each LSE will submit to the ISO copies of all executed Installed Capacity contracts (excluding pricing information) and documentation of arrangements by the LSE to use its own

Generation to meet its requirement for the upcoming Capability Period.

Each LSE also will submit the following information to the ISO, in accordance with ISO Procedures, for determining Installed Capacity requirements: (a) Load name and location (zone); (b) its forecasted demand within each Transmission District coincident with that Transmission District's independent (non-coincident with NYCA) peak; (c) its forecasted average demand within each Transmission District for the Capability Year; (d) its forecasted demand within each Locality coincident with that Locality's independent (non-coincident with NYCA) peak load; and (e) its forecasted average demand within each Locality for the Capability Year.

Each LSE will satisfy the ISO's documentation requirements no later than thirty (30) days prior to the beginning of the upcoming Capability Period to demonstrate adequate Installed Capacity for that Capability Period.

5.11 Requirements of Installed Capacity Providers

Providers of Installed Capacity to the NYCA shall: (i) provide information reasonably requested by the ISO including the name and location of Generators and Interruptible Load Resources; (ii) provide documentation to the ISO of Dependable Maximum Net Capability ("DMNC") testing no more than twelve (12) months old for a Generator for each Capability Period (or historical production data by Capability Period no more than twelve (12) months old or documentation of sustained disconnection for one (1) hour or longer, no more than one (1) year old for an Interruptible Load Resource, in accordance with ISO Procedures; (iii) abide by the ISO Generator maintenance coordination procedures; (iv) provide the expected return date from any outages (including partial outages) to the ISO and to the Transmission Owner to which the Generator is electrically interconnected; (v) not utilize the same Installed Capacity for more than one (1) buyer at the same time; (vi) if the resource is a Generator, either use it in Day-Ahead Bilateral Transactions to supply Load within the NYCA or bid it into the Day-Ahead Energy Market (unless the Generator is unable to meet its commitments due to a maintenance or forced outage); (vii) if the resource is an Interruptible Load Resource, make a Bid in the Day-Ahead Market for both Energy and Operating Reserves; and (viii) abide by ISO Procedures.

If a Generator is selected in the Day-Ahead Market and fails to produce Energy, or if a Generator fails an Availability test, the resource will be considered to be unavailable. If not selected to provide Energy or Operating Reserves in the Day-Ahead Market, the provider may participate in the Real-Time Market or in other Energy markets, Bilateral Transactions, or Transactions with other Control Areas subject to Reliability Rules and ISO Procedures.

Generators not participating as Installed Capacity providers will remain eligible for the Installed Capacity market. In order to remain eligible they must continue to bid into the Day-Ahead Market and adhere to the ISO Day-Ahead Market start-up time requirements for reliability during the contract period (unless they are on maintenance or forced outage). Interruptible Load Resources providing Installed Capacity will implement Load Curtailments at the direction of the ISO, in accordance with ISO Procedures.

If a Generator does not meet the Availability standard for its Generator Class, the amount of qualified Installed Capacity will be reduced in accordance with ISO Procedures.

All Generators located within the NYCA or supplying Installed Capacity to the NYCA must submit a confidential notification to the ISO of their proposed outage schedule in accordance with NPCC time schedules. The Generator owners will provide a three (3) year schedule of annual scheduled outages by July 1 (i.e., six (6) months before the start of each calendar year. Transmission Owners will be notified of these and subsequently revised outage schedules. Based upon a reliability assessment, if Operating Reserve deficiencies are projected to occur in certain weeks for the upcoming calendar year, the ISO will request voluntary maintenance re-scheduling. If voluntary re-scheduling in ineffective, the ISO will invoke forced re-scheduling of outages planned by Generators supplying Installed Capacity to the NYCA to ensure that projected Operating Reserves over the upcoming year are adequate. This re-scheduling will be based on ISO Procedures. A Supplier intending to provide Installed Capacity in the upcoming year must notify the ISO by July 1 of the prior year so the Supplier can be made subject to forced re-scheduling of its proposed maintenance outage scheduled by the ISO, if needed.

5.12 Installed Capacity Acquisition

An LSE may choose to satisfy its Installed Capacity requirements through an ISO facilitated auction for Installed Capacity resources, using Bids from Generators or Interruptible Load Resources. A Bid-based auction will be held upon an LSE's request for an auction. The auction will make available Installed Capacity resources for a Capability Period to meet the ISO requirements including Locational Installed Capacity Requirements, and will establish a separate market clearing price for each Locality and for the remainder of the NYCA. Each LSE purchasing Installed Capacity in the auction will pay the market clearing price(s) for Installed Capacity resources for the Locality where it requested the resource to be located. Each LSE requesting Installed Capacity will be pro-rated Installed Capacity resources at auction per their request and in the proper Locality and be charged accordingly. In establishing bidding rules, the ISO will accommodate requirements related to tax-exempt bonds. The ISO will enforce market power mitigation measures as approved by the Commission in the auction. LSEs procuring Installed Capacity through an auction shall be awarded a common interest in all resources participating in the auction, subject to locational requirements for Capacity. The auction will be conducted in accordance with ISO Procedures. Bilateral contracts for Installed Capacity will be permitted for those LSEs desiring to engage in such Transactions and will be separate from the auction process.

LSEs may receive Installed Capacity credit for meeting Installed Capacity requirements from Generators located outside the NYCA provided that those Generators meet the ISO requirements for Installed Capacity providers. Subject to provisions for existing contracts for External Installed Capacity, the amount of Installed Capacity provided by Generators located outside the NYCA will be limited to a level, to be determined by the ISO, which will not reduce the interconnection assistance benefits from neighboring Control Areas. LSEs with External Installed Capacity as of the effective date of the Tariff will be entitled to designate External Installed Capacity at the same NYCA Interface with another Control Area, in the same amounts in effect on the effective date of the Tariff. To the extent such External Installed Capacity corresponds to Existing Transmission Capacity for Native Load as reflected in Table 3 to Attachment L to the ISO OATT, these External Installed Capacity rights will continue without term and shall be allocated to the LSE's retail access customers in accordance with the LSE's retail access program on file with the PSC and subject to any necessary filings with the Commission. External Installed Capacity rights existing as of the effective date of the Tariff that do not correspond to Table 3 of Attachment L to the ISO OATT shall survive for the term of the External Installed Capacity contract or until the External Generator is retired.

5.13 Installed Capacity Deficiencies

The ISO shall determine whether an LSE has satisfied its Installed Capacity requirement, adjusted for Load transferred between LSEs, during any Capability Period, by subtracting the Installed Capacity (in MW) that it has secured for a Capability Period (adjusted if necessary to reflect the failure of any of those qualified Suppliers providing Installed Capacity to meet the ISO's Availability requirement) from the adjusted Installed Capacity requirement determined in accordance with Sections 5.10.1 and 5.10.2. These calculations will be performed after the end of the Capability Period using actual Loads. An LSE that fails to satisfy its Installed Capacity requirement will be subject to a deficiency payment, as defined below. An LSE, however, may mitigate or avoid the deficiency payment by purchasing additional Installed Capacity from LSEs that had surplus Installed Capacity during the same Capability Period. The LSE also may purchase additional Installed Capacity from qualified Suppliers. A qualified Installed Capacity Supplier is one that has met the requirements for Installed Capacity Suppliers described in Section 5.11. The amount of

Installed Capacity that such a Supplier may provide will depend upon the actual Availability of the Generators supplying that Installed Capacity in accordance with ISO Procedures.

An LSE's Installed Capacity Deficiency for the Capability Period =

LSE_{DEF} = <GREATER OF> 0MW <OR> $IC_{REQ} - LSE_{IC}$

Where: IC_{REQ} = Installed Capacity requirement for this LSE based on actual peak Load

LSE_{IC} = Total of actual equivalent Installed Capacity that was committed to this LSE for the Capability Period, accounting for Availability adjustments, if applicable

The determination of the deficiency payment shall be calculated as the product of: (a) the number of MW of Installed Capacity by which a LSE is deficient; and (b) the ISO's deficiency charge per MW in that Capability Period. The Installed Capacity deficiency charge shall be as follows:

LOCATION	INTERIM FIRST THREE YEARS	END-STATE AFTER THREE YEARS
In-City New York City (LBMP Load Zone)	**$75/kW per Capability Period**	**3 Times Localized Levelized Embedded Cost of GT**
Long Island (LBMP Load Zone K)	**Year 1: $60/kW per Capability Period Year 2: $65/kW per Capability Period Year 3: $70/kW per Capability Period**	**3 Times Localized Levelized Embedded Cost of GT**
All Other LBMP Load Zones in New York	**Year 1: $52.5/kW per Capability Period Year 2: $57.5 Year 3: $62.5**	**3 Times Localized Levelized Embedded Cost of GT**

These payments shall be the responsibility of the appropriate LSE. These deficiency payments will be applied to reduce the Rate Schedule 1 charge under this Tariff.

ARTICLE 6

CONFIDENTIALITY

6.1 Access to Confidential Information

The ISO may request, and the Customer shall provide, Confidential Information consistent with the disclosure requirements set forth in the ISO Services Tariff (as provided for below). The ISO shall use reasonable procedures to prevent the disclosure of Confidential Information and shall not publish, disclose or otherwise divulge Confidential Information to any person or entity without the prior written consent of the party supplying such Confidential Information, except as provided for under the ISO Market Power Monitoring Plan. The provisions of this Section shall not apply to any Confidential Information: (i) which was in the public domain at the time of disclosure hereunder; (ii) which thereafter passes into the public domain by acts other than the acts of the ISO; or (iii) that the ISO is required to make publicly available by the Commission, the PSC or other legal process, or for reliability purposes pursuant to Good Utility Practice.

A Customer may request that the ISO keep confidential from another entity Confidential Information that the other entity does not require to perform its obligations and duties hereunder. The Customer must state in writing that the information is to be treated as Confidential Information and the reasons for treating it as Confidential Information, otherwise information will be treated as non-Confidential Information.

6.2 Use of Confidential Information

The ISO shall use Confidential Information for the exclusive purpose of performing its obligations hereunder and under any Service Agreement. The ISO will treat this information in conformity with the standards of conduct contained in Part 37 of the Commission's Regulations and the Code of Conduct set forth in Attachment F to the ISO OATT.

6.3 Disclosure of Bid Information

Pursuant to Commission requirements, the ISO shall make public Bid information from the Energy, Capacity and Ancillary Services markets six-months after the Bids are submitted. Prior to such disclosure, Bid information submitted to the ISO by Market Participants shall be considered Confidential Information.

6.4 Survival

This Article 6 will survive the termination of the ISO Services Tariff and any associated Service Agreement.

ARTICLE 7

BILLING AND PAYMENT

7.1 ISO Clearing Account

The ISO will provide Settlement and Billing information to Customers. The ISO will establish an account (the "ISO Clearing Account"), and Customers will be directed to make payments into the ISO Clearing Account according to the Settlement information provided by the ISO. The ISO shall verify that Customers paying into the ISO Clearing Account have made the correct payments within the time period allotted for such payment. If a Customer fails to make a payment within the required time period or pays less than the amount due, the ISO shall take measures pursuant to Section 7.5. The ISO will make payments through the ISO Clearing Account to all entities owed money in accordance with the ISO OATT and the ISO Services Tariff.

The ISO Clearing Account established herein shall be opened and operated by the ISO as trustee in trust for ISO creditors and ISO debtors in accordance with this Tariff. The account shall be maintained at a bank or other financial institution in New York State as a trust account. Such account shall not be commingled with any other ISO accounts. The ISO will not take title to the funds held in the ISO Clearing Account. Nor will the ISO take title to any Energy, Capacity or Ancillary Services.

The ISO will inform each Customer that purchases Energy, Capacity, or Ancillary Services in the Day-Ahead and Real-Time Markets administered by the ISO of the payments due, according to the Day-Ahead and Real-Time Settlements. For each service provided for under the ISO Services Tariff, the payments due to the ISO shall be netted against the corresponding amounts due to the Customer for generating Energy and providing Capacity and Ancillary Services in the ISO Administered Markets.

A Customer owing payments on net will make those payments to the ISO Clearing Account on the payment date. A Customer owed payments on net will receive payments from the ISO Clearing Account on the payment date. Payments will be made by wire transfer unless other arrangements are made. The ISO will provide a detailed statement of such receipts or payments. Any residual collections remaining in this account related to services provided by the ISO under the ISO Services Tariff will be used to reduce the Rate Schedule 1 charge under the ISO Services Tariff.

7.2 Billing Procedures and Payments

A. Invoices and Settlement Information.

Payments for TSCs, Congestion and TCCs shall be issued in accordance with the Settlement and billing procedures under the ISO OATT. Charges may be based in whole or in part on estimates. Settlement information rendered hereunder shall be mailed to the Customer at the address contained in the Service Agreement.

Within a reasonable time after the first day of each month, the ISO shall submit an invoice to the Customer for the net amount owed by the Customer for each of the services furnished under the ISO OATT and the ISO Services Tariff during the preceding month. Such invoices shall also show the net amount owed to the Customer by type of service. Charges may be based in whole or in part on estimates. Any charges based on estimates shall be subject to true-up, including interest calculated from the first due date after the service was rendered in accordance with Section 7.3, in invoices subsequently issued by the ISO after the ISO has obtained the requisite actual information. The ISO may net any overpayment, including interest calculated from the date the overpayment was made in accordance with Section 7.3, by the Customer for past estimated charges against current amounts due from the Customer or, if the Customer has no outstanding amounts due, the ISO may pay to the Customer an amount equal to the overpayment.

B. Payment by the Customer

Invoices shall be paid by the Customer within twenty (20) days of receipt. All payments shall be made by wire transfer in immediately available funds payable to the ISO as trustee of the ISO Clearing Account.

C. Payments by the ISO

The ISO shall pay all net monies owed to a Customer within twenty (20) days of the date of the invoice. All payments shall be made by wire transfer in immediately available funds payable to the Customer by the ISO or trustee of the ISO Clearing Account.

D. Verification of Payments

The ISO shall institute procedures to verify that all payments owed by Customers to the ISO Clearing Account have been paid in a timely manner. The ISO shall be responsible for ensuring that such payments are made within the prescribed period of time and for instituting collection procedures to collect those monies that have not been timely paid. The ISO shall also institute procedures to ensure that monies owed to Customers are paid in a timely manner, and the ISO shall be responsible for ensuring that such payments are made.

7.3 Interest on Unpaid Balances

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

If the ISO is unable to provide Settlement information on time due to the action or inaction of or caused by the Customer, in addition to any other remedies the ISO may have at law or in equity, the Customer shall pay interest on amounts due, as calculated above, from the first day of the month following the month in which charges are accrued to the time of payment of those charges.

7.4 Billing Dispute

Settlement information shall be subject to correction or adjustment for errors in arithmetic, computation or estimation, within twenty-four (24) months from the month in which service is rendered.

A Customer's right to challenge the accuracy of Settlement information is limited to twenty-four (24) months from the month in which service is rendered. If a Customer wishes to challenge Settlement information for accuracy, the Customer shall first make payment in full, including any amounts in dispute. If the ISO determines that an overpayment has been made by the Customer, the ISO shall refund the overpayment to the Customer, including interest calculated from the date the overpayment was made in accordance with Section 7.3.

7.5 Customer Default

A. An event of default ("Default") shall occur in the event a Customer (the "Defaulting Party") shall:

(i) fail to provide adequate assurance of performance to the ISO within a period of five (5) business days of a demand for such assurance;

(ii) make an assignment or any general arrangement for the benefit of creditors;

(iii) default in a payment obligation to the ISO which is not cured within two (2) business days after receipt of written notice of such default provided by the ISO;

(iv) file a petition or otherwise commence, authorize, or acquiesce in the commencement of a case, petition, proceeding or cause of action under any bankruptcy or insolvency law or similar law for the protection of debtors or creditors, or have such a petition, case, proceeding or cause of action filed or commenced against it and such case, petition, proceeding or cause of action is not withdrawn or dismissed within thirty (30) days after such filing or commencement;

(v) otherwise become bankrupt or insolvent (however evidenced);

(vi) be unable or unwilling to pay its debts to third parties as they fall due;

(vii) otherwise become adjudicated a debtor in bankruptcy or insolvent (however evidenced);

(viii) be unable (or admits in writing its inability) generally to pay its debts as they become due;

(ix) be dissolved (other than pursuant to a consolidation, acquisition, amalgamation or merger);

(x) have a resolution passed for its winding-up official management or liquidation (other than pursuant to a consolidation, acquisition, amalgamation or merger);

(xi) seek or become subject to the appointment of an administrator, provisional liquidator, conservator, assignee, receiver, trustee, custodian or other similar entity or official for all or substantially all of its assets;

(xii) have a secured party take possession of all or substantially all of its assets or has a distress, levy, execution, attachment, sequestration or other legal process levied, enforced or sued on or against all or substantially all of its assets and such secured party maintains possession, or any such process is not dismissed, discharged, stayed or restrained, in each case within thirty (30) days thereafter;

(xiii) cause or is subject to any event with respect to which, under the applicable laws of any jurisdiction, said event has an analogous effect to any of the events specified in clauses (iv) to (xii) (inclusive);

(xiv) take any action in furtherance of, or indicating its consent to, approval of, or acquiescence in, any of the foregoing acts; or

(xv) fail to perform any material covenant set forth in the Tariff or a Service Agreement (other than the events that are otherwise specifically covered in this Section as a separate Event of Default), and such failure is not excused by Force Majeure or cured within five (5) business days after written notice thereof to the Defaulting Party; or a party fails to, or can no longer, demonstrate its creditworthiness after five (5) days notice of a demand to demonstrate.

B. In the event of Default by a Customer, the ISO shall have the right to suspend performance of the Service Agreement with the Customer, terminate the Service Agreement, immediately upon notice to the Commission, or both, in addition to any and all other remedies available hereunder or pursuant to law or in equity.

C. By entering into transactions under this Tariff, the Customer agrees that its Service Agreement and transactions under this Tariff shall constitute a “forward contract” within the meaning of the United States Bankruptcy Code.

D. The ISO shall have the right to apply any amounts owed Customer pursuant to this Tariff against any amounts owed to the ISO by a Customer.

7.6 Survival

This Article 7 will survive the termination of the ISO Services Tariff and any associated Service Agreement.

ARTICLE 8

ELIGIBILITY FOR ISO SERVICES

In order to purchase or supply Energy or Capacity or to supply Ancillary Services in the ISO Administered Markets, Customers must satisfy the requirements of this Article.

8.1 Requirements Common to all Customers

A. Creditworthiness

All Customers shall satisfy the following requirements prior to entering into a Transaction with the ISO. For the purpose of determining the ability of the Customer to meet its obligations related to services hereunder, the ISO shall require compliance with reasonable credit review procedures in accordance with standard commercial practices. In addition, the ISO may require the Customer to provide and maintain in effect during the term of the Service Agreement, an unconditional and irrevocable letter of credit as security to meet its responsibilities and obligations under the ISO Services Tariff, or an alternative form of security proposed by the Customer and acceptable to the ISO and consistent with commercial practices established by the Uniform Commercial Code that protects the ISO against the risk of non-payment.

Any service may be terminated by the ISO prior to, or any time after, the commencement of the service if the Customer fails to, or can no longer, demonstrate its creditworthiness. Each Customer shall be responsible for providing the information specified in this Section. Each Customer will be considered creditworthy if: (i) the Customer's long-term unsecured debt securities are, and remain, rated a minimum of BBB or Baa2 by Standard & Poor's or Moody's, respectively; (ii) the Customer either prepays for service or provides an irrevocable standby letter of credit issued by a domestic or Canadian bank with a minimum A (Standard & Poor's or Dominion), or A2 (Moody's) long-term unsecured debt rating, for an amount equal to the estimated sum of the charges pursuant to Article 7 for the three (3) individual months when such charges would be greatest over rolling twelve-month periods; (iii) the Customer has, as determined by the ISO in its reasonable discretion, a qualified long-term payment history with the ISO or an individual Transmission Owner; or (iv) the Customer's parent company, in a form satisfactory to the ISO, guarantees the Customer's responsibility for all financial obligations associated with services and responsibilities hereunder and such parent company conforms to the minimum ratings specified above.

B. Completed Application and Minimum Technical Requirements

A Customer shall submit a Completed Application in accordance with Article 9 and shall receive ISO approval prior to obtaining any services under the ISO Services Tariff. A Customer also shall demonstrate to the ISO's reasonable satisfaction that it is capable of performing all functions required by the ISO Services Tariff including operational communications, financial and Settlement requirements.

8.2 Additional Requirements Applicable to Suppliers

In addition to the requirements set forth in Section 8.1 above, Suppliers shall satisfy the communication requirements of Article 4 and the metering requirements of Article 13 prior to entering into a Transaction with the ISO.

8.3 Additional Requirements Applicable to LSEs

In addition to the requirements set forth in Section 8.1 above, each LSE shall satisfy the following requirements prior to taking services under the Tariff:

A. All requirements and conditions contained within an approved retail access plan in the service territory of the Transmission Owner in which the LSE's Load is located; which retail access plan has been approved by the PSC or other appropriate authority or, in the case of the LIPA, has been approved by the Trustees of the Long Island Power Authority.

B. All New York State application and license requirements, and any other authorization required by New York State to serve retail Load; and

C. The LSE must be: (a) aggregating or serving Load that is of an amount greater than or equal to one (1) MW in each hour as measured between a single Point of Injection and a single Point of Withdrawal; or (b) making purchases from the ISO Administered Markets at a single bus of an amount greater than or equal to one (1) MW in each hour.

ARTICLE 9

APPLICATION AND REGISTRATION PROCEDURE

9.1 Application

Each Customer requesting to schedule, take or provide any services under the ISO Services Tariff must apply to the ISO in writing at least sixty (60) days in advance of the month in which service is to commence. The ISO will consider requests for such services on shorter notice when feasible. Service commencement will depend on the ISO's ability to accommodate the request. To apply, the Customer shall complete and deliver a Service Agreement (in the form of Attachment A) and an Application to the ISO.

9.2 Completed Application

A Completed Application shall provide all of the information reasonably required by the ISO to permit the ISO to perform its responsibilities under the ISO Services Tariff. The ISO shall treat the information provided in the Application as Confidential Information except to the extent that disclosure of the information is required by the ISO Services Tariff, by regulatory or judicial order or for reliability purposes pursuant to Good Utility Practice. The ISO also shall treat the information in conformity with the standards of conduct contained in Part 37 of the Commission's Regulations and the Code of Conduct set forth in Attachment F to the ISO OATT.

9.3 Approval of Application and/or Notice of Deficient Application

The ISO will promptly review the Application and may request additional information to determine whether the applicant meets the ISO's minimum financial and technical requirements. The ISO will notify the applicant within thirty (30) days of receipt of a Completed Application. If the ISO rejects an Application, the ISO shall provide a written explanation within fourteen (14) days of the rejection. The ISO will attempt to remedy minor deficiencies in the Application through informal communications with the applicant. If such efforts are unsuccessful, the ISO shall return the Application.

9.4 Filing of Service Agreement

The ISO will file Service Agreements with the Commission in compliance with applicable Commission regulations and the ISO Services Tariff.

ARTICLE 10

RECORDKEEPING AND AUDIT

The ISO and each Customer shall keep complete and accurate records of service taken or provided under the ISO Services Tariff including, but not limited to, meter readings (if any), dispatch logs, Bid data and other memoranda of Applications and service. Upon thirty (30) days prior written notice, and subject to the provisions in Article 6, the Customer, the ISO, the applicable Transmission Owner, the NYSRC, the Commission or the PSC shall have the right to inspect all records, meter readings and memoranda for the purpose of ascertaining the accuracy of all Settlement information prepared pursuant to Article 7 and compliance with the provisions of the ISO Services Tariff and the Reliability Rules. These inspections shall be performed in a reasonable manner and so as to avoid disrupting the business of the party whose records are being inspected. The costs of all these inspections, including the costs of the party whose records are being inspected, shall be borne by the inspecting party, except that there shall be no charge to the PSC or the Commission for such inspections or for the costs associated with such inspections. Historical records shall be kept as follows: (i) Settlement information rendered under the ISO Services Tariff shall be maintained for at least twenty-four (24) months from the date that Settlement information is rendered; (ii) Applications under the ISO Services Tariff shall be maintained for twelve (12) months after the date of termination of the service or twelve (12) months after the Application was rejected; and (iii) any other records associated with service under the ISO Services Tariff that are not listed above shall be maintained for twelve (12) months after the date of termination of the service.

ARTICLE 11

DISPUTE RESOLUTION PROCEDURES

11.1 Internal Dispute Resolution Procedures

Any dispute between or among Customers and/or the ISO involving service under the ISO Services Tariff (excluding applications for rate changes or other changes to the Tariff), ISO Procedures or to any Service Agreement entered into under the Tariff shall be presented directly to a senior representative of each party to the dispute for resolution on an informal basis as promptly as practicable.

If the designated representatives are unable to resolve the dispute within thirty (30) days by mutual agreement, the dispute may be submitted to the ISO's Dispute Resolution Administrator ("DRA"). The party submitting the matter to the DRA shall include a written statement describing the nature of the dispute and the issues to be resolved. Any subsequent mediation or arbitration process shall be limited to the issues presented for resolution.

The DRA may submit disputes to non-binding mediation where the subject matter of the dispute involves the proposed change or modification of a rule, rate, Service Agreement or ISO Services Tariff provision. The DRA may submit disputes to binding arbitration which involve interpretation of a rule, rate, Service Agreement or ISO Services Tariff provision. Both the mediator and the arbitrator shall have the authorization to dismiss a dispute if:

1. The dispute did not arise under the ISO Services Tariff; or
2. The claim is de minimis.

11.2 Non-Binding Mediation

If the DRA refers the dispute to non-binding mediation, then the following procedure will be followed:

The DRA shall have ten (10) days from the date of such referral to distribute a list of ten (10) qualified mediators to the disputing parties. Absent the express written consent of all disputing parties, as to any particular individual, no person shall be eligible for selection as mediator who is a past or present officer, employee or consultant to any of the disputing parties, or of any entity related to or Affiliated with any of the disputing parties or is otherwise interested in the matter to be mediated. Any individual designated as mediator shall make known to the disputing parties any such disqualifying relationship and a new mediator shall be designated.

If the disputing parties cannot agree upon a mediator, the disputing parties shall take turns striking names from a list supplied by the DRA with a disputing party chosen by lot, first striking a name. The last remaining name shall be designated as the mediator. If that individual is unable or unwilling to serve, the individual last stricken from the list shall be designated and the process repeated until an individual is selected that is able and willing to serve.

The disputing parties shall attempt in good faith to resolve their dispute in accordance with the schedule established by the mediator but in no event, may the schedule extend beyond ninety (90) days from the date of appointment of the mediator.

The mediator may require the disputing parties to:

1. submit written statements of issue(s) and position(s);
2. meet for discussions;
3. provide expert testimony and exhibits; and
4. comply with the mediation procedures designated by the DRA and/or the mediator.

If the parties have not resolved the dispute within ninety (90) days after the date the mediator was appointed, then the mediator shall promptly provide the disputing parties and the DRA with a written, confidential, non-binding recommendation to resolve the dispute. The recommendation shall include an assessment by the mediator of the merits of the principal positions being advanced by each of the parties to the dispute. The parties to the dispute shall then meet in a good faith attempt to resolve the dispute in light of the mediator's recommendation. This recommendation shall be limited to resolving the specific issues presented for mediation.

If the parties are still unable to resolve the dispute, then:

A. any dispute not involving a proposed change or modification of a rule, rate, Service Agreement or ISO Services Tariff provision may be referred to the arbitration process described below; or

B. any disputing party may resort to regulatory or judicial proceedings as provided for under the ISO Services Tariff; and

C. the recommendation of the mediator, and any other statements made by any party during the mediation process, shall not be admissible for any purpose, in any subsequent proceeding.

Each party to the dispute will bear a pro rata portion of the costs associated with the time, expenses and other charges of the mediator. Each party shall bear its own costs, including attorney and expert fees.

11.3 Arbitration

If the DRA refers the dispute to arbitration, then the following procedure will be followed:

The DRA shall have ten (10) days from the date of such decision to distribute a list of qualified arbitrators to the disputing parties. No person shall be eligible for selection as an arbitrator who is a past or present officer, employee of or consultant to any of the disputing parties, or of an entity related to or affiliated with any of the disputing parties, or is otherwise interested in the matter to be arbitrated, except upon the express written consent of the parties. Any individual designated as an arbitrator shall make known to the disputing parties any such disqualifying relationship or interest and a new arbitrator shall be designated, unless express written consent is provided by each party.

If the disputing parties cannot agree upon an arbitrator, the disputing parties shall take turns striking names from a list of ten (10) qualified individuals supplied by the DRA. The party to first strike a name should be chosen by lot. The last-remaining name not stricken shall be designated as the arbitrator. If that individual is unable or unwilling to serve, the individual last stricken from the list shall be designated and the process repeated until an individual is selected that is able and willing to serve.

The arbitrator shall have no power to modify or change any agreement, tariff or rule or otherwise create any additional rights or obligations for any party. The scope of the arbitrator's decision shall be limited to the issues presented for arbitration. The arbitrator shall determine discovery procedures, intervention rights, how evidence shall be taken, what written submittals may be made, and other such procedural matters, taking into account the complexity of the issues involved, the extent to which factual matters are disputed, and the extent to which the credibility of witnesses is relevant to a resolution. Each party to the dispute shall produce all evidence determined by the arbitrator to be relevant to the issues presented. To the extent such evidence involves proprietary or Confidential Information, the arbitrator may issue an appropriate protective order which shall be complied with by all disputing parties. The arbitrator may elect to resolve the arbitration matter solely on the basis of written evidence and arguments.

The arbitrator shall consider all issues underlying the dispute, and the arbitrator shall take evidence submitted by the disputing parties in accordance with procedures established by the arbitrator and may request additional information including the opinion of recognized technical bodies or experts. The parties shall be afforded a reasonable opportunity to rebut any such additional information.

Absent agreement to the contrary by all disputing parties, no person or entity that is not a party to the dispute shall be permitted to intervene. Within ninety (90) days of the appointment of the arbitrator, and after providing the parties with an opportunity to be heard, the arbitrator shall render a written decision, including findings of fact and the legal basis for the decision. The arbitrator will follow the Commercial Arbitration Rules of the American Arbitration Association.

Under the following circumstances, the decision of the arbitrator shall be final and binding upon the parties:

1. all parties agree that the decision will be binding; or
2. the dispute involves a claim that a party owes another party a sum of money less than $500,000.

If the arbitrator concludes that no proposed award is consistent with the ISO Services Tariff, the FPA and Commission's then-applicable standards and policies, or would address all issues in dispute, the arbitrator shall develop a compromise solution consistent with the terms of the ISO Services Tariff. A written decision explaining the basis for the award shall be provided by the arbitrator to the parties and the DRA. No award shall be deemed to be precedential in any other arbitration related to a different dispute.

All costs associated with the time, expenses and other charges of the arbitrators shall be borne by the unsuccessful party. Each party shall bear its own costs, including attorney and expert fees.

All arbitration decisions that affect matters subject to the jurisdiction of the Commission shall be filed with the Commission. Any arbitration decision that affects matters subject to the jurisdiction of the PSC under the PSL may be filed with the PSC. The judgment of the arbitrator may be entered on the award by any court in New York having jurisdiction. Within one (1) year of the arbitration decision, a party may request that the Commission or any other federal, state, regulatory or judicial authority (in the State of New York) having jurisdiction over such matter vacate, modify or take such other action as may be appropriate with respect to any arbitration decision that is:

1. based upon an error of law;
2. contrary to the statutes, rules or regulations administered by such authority;
3. violative of the Federal Arbitration Act or Administrative Dispute Resolution Act;
4. based on conduct by an arbitrator that is violative of the Federal Arbitration Act or Administrative Dispute Resolution Act; or
5. involves a dispute in excess of $500,000.

Nothing in this Section shall restrict the rights of any party to file a complaint, rate or tariff or other contract change with the Commission under the relevant provisions of the FPA. No arbitrator shall select an award which requires the transmission of electricity under circumstances where the Commission is precluded from ordering Transmission Services pursuant to FPA Section 212(h).

ARTICLE 12

LIABILITY AND INDEMNIFICATION

12.1 Force Majeure

The ISO, the NYSRC, the Transmission Owners and any Customer or Market Participant shall not be considered to be in default or breach under the ISO Services Tariff or a Service Agreement, and shall be excused from performance, or liability for damages to any other party, if and to the extent it shall be delayed in or prevented from performing or carrying out any of the provisions of the ISO Services Tariff or a Service Agreement, except the obligation to pay any amount when due, arising out of or from any act, omission or circumstance occasioned by or in consequence of any act of God, labor disturbance, failure of contractors or suppliers of materials, act of the public enemy, war, invasion, insurrection, riot, fire, storm, flood, ice, explosion, breakage or accident to machinery or equipment, or by any other cause or causes beyond such party's reasonable control, including any Curtailment, order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or by the making of repairs necessitated by an Emergency circumstance not limited to those listed above upon the property or equipment of the ISO or any party to the ISO Agreement. Nothing contained in this Section shall relieve any entity of the obligation to make payments when due hereunder or pursuant to a Service Agreement. Any party claiming a force majeure event shall use reasonable diligence to remove the condition that prevents performance, except the settlement of any labor disturbance shall be in the sole judgment of the affected party.

Nothing contained in this Section shall relieve a party to a Service Agreement of its obligations to pay all charges due under the Tariff, even if such charges would not have been due had the party claiming force majeure not experienced the force majeure.

12.2 Claims by Employees and Insurance

Each Transmission Owner, Customer, Market Participant and the ISO shall be solely responsible for and shall bear all of the costs of claims by its own employees, contractors, or agents arising under, and covered by, any workers' compensation law. Each of the parties shall furnish, at its sole expense, such insurance coverage and such evidence thereof, or evidence of self-insurance, as is reasonably necessary to meet its obligations under this Section.

12.3 Limitation on Liability

The ISO, Transmission Owners and NYSRC shall not be liable (whether based on contract, indemnification, warranty, tort, strict liability or otherwise) to any Customer, Market Participant, or any third party or other party for any damages whatsoever including, without limitation, direct, incidental, consequential, punitive, special, exemplary or indirect damages resulting from any act or omission in any way associated with a Service Agreement or the ISO Services Tariff, except to the extent that the ISO, Transmission Owner or NYSRC is found liable for gross negligence or intentional misconduct, in which case the ISO, Transmission Owner or NYSRC will not be liable for any incidental, consequential, punitive, special, exemplary or indirect damages. This Section, however, does not limit in any way the ISO's obligation to indemnify the Transmission Owners pursuant to the ISO/TO Agreement or any other agreement.

Nothing in the ISO Services Tariff, or any Service Agreement pursuant to the ISO Services Tariff, express or implied, is intended to confer on any person, other than the parties to a Service Agreement, any rights or remedies under or by reason of the ISO Services Tariff.

12.4 Indemnification

For the purpose of this Section, the terms Market Participant(s) and Customer(s) shall not include Transmission Owners, either in their role as Transmission Owners or in their role as Market Participants or Customers.

Subject to the ISO's obligations to the Transmission Owners under the ISO/TO Agreement and the ISO Agreement, each Customer and Market Participant shall indemnify, save harmless and defend the ISO, the Transmission Owners and the NYSRC including their directors, officers, employees, trustees, and agents, or each of them (individually the "Indemnitee" or collectively the "Indemnitees") from and against all claims, demands, losses, liabilities, judgments, damages, and related costs and expenses (including, without limitation, reasonable attorney and expert fees, and disbursements incurred by the Indemnitees in any actions or proceedings between the Indemnitees and a third party, the Customer or Market Participant or any other party) arising out of or related to the Indemnitee's or the Customer's acts or omissions related in any way to performance under the ISO Services Tariff, a Service Agreement or an ISO Related Agreement, except to the extent that the Indemnitees are found liable for gross negligence or intentional misconduct.

12.5 Other Remedies

Nothing in the ISO Services Tariff shall be construed as in any way to limit the Transmission Owner's rights and remedies, at law or in equity, with respect to a party in the event of an act or omission related to the ISO Services Tariff by such party.

12.6 Survival

The provisions of this Article 12, "Liability and Indemnification," shall survive termination or expiration of the ISO Services Tariff or any associated Service Agreement.

ARTICLE 13

METERING

13.1 General Requirements

Existing metering in the NYCA provides revenue-quality metering information among the currently designated electrical zones separated by the designated transmission Interfaces. In addition, sufficient metering information will be made available by the ISO to calculate Load for the individual Transmission Owners within each Load Zone. The ISO will require adequate metering for all Generators and Loads within the NYCA to ensure the reliable operation of the NYS Power System.

13.2 Requirements Pertaining to Customers

Customers shall provide to the ISO such information and data as the ISO reasonably deems necessary in order to perform its functions and fulfill its responsibilities under the ISO Services Tariff and in accordance with the ISO Market Power Monitoring Program. Such information will be provided on a timely basis and in the formats prescribed in the ISO Procedures. The ISO shall establish metering specifications and standards for all metering that is used as a data source by the ISO. Customers shall install and maintain such metering at their own expense and deliver data to the ISO without charge.

A Customer taking service under the ISO Services Tariff will make available to the ISO metered data that meets ISO requirements by one of the following means: (i) direct transmission to the ISO; (ii) direct transmission to the ISO through Transmission Owner communications equipment; or (iii) indirectly through metering provided by the Transmission Owner in whose Load Zone it is located.

The Customer also shall provide its metered data to the Transmission Owner in whose Load Zone it is located, to the extent that the Transmission Owner determines that the metered data provided to the ISO is required for its system operation and planning functions, for the billing of services it provides to the Customer, or to perform calculations required as part of the ISO Settlement procedures.

Load Serving Entities

Any Load that is not directly metered, as described above, will have its Load determined by the Transmission Owner in whose Load Zone it is located in accordance with the Transmission Owner's retail access plan on file with the PSC or otherwise authorized.

Ancillary Service Suppliers

Suppliers shall ensure that adequate metering data is made available to the ISO as described above. Additionally, for operational purposes, metered data provided to the ISO must also simultaneously be provided to the Transmission Owner, which will handle such information in conformity with the OASIS standards of conduct as specified in Order No. 889.

Third Party Metering Services

Customers whose metering services are provided by third parties qualified under rules, regulations and procedures of applicable state regulatory authorities shall be responsible to ensure that all data described in this Section are satisfactorily made available to the ISO and applicable Transmission Owner(s) by those third parties.

Estimation of Metering

In the event of a meter malfunction or inadequate metering data, the ISO may use estimates to determine Customer's rights and responsibilities under the ISO Services Tariff.

ARTICLE 14

MISCELLANEOUS

14.1 Notices

Except as specified in the ISO Procedures, all written notices under the ISO Services Tariff shall be deemed as having been given: (i) when delivered in person; (ii) when sent by United States registered or certified mail (return receipt requested), postage prepaid; or (iii) when sent by a reputable overnight courier to the other party at the address stated in the Service Agreement between the ISO and each Customer or at the last changed address given by the other party as hereinafter specified. Either party may, at any time, change its address for notification purposes by sending the other party written notice stating the change and setting forth the new address. The ISO shall adopt procedures for the provision of all notices and protocols required to implement ISO Services Tariff.

14.2 Tax Exempt Financing Pursuant to Section 142 (f) of the Internal Revenue Code

This provision is applicable only to Transmission Owners that have financed facilities for the local furnishing of Energy with Local Furnishing Bonds as described in Section 142(f) of the Internal Revenue Code ("Local Furnishing Bonds"). Notwithstanding any other provision of the ISO Services Tariff, neither the ISO nor the Transmission Owner shall be required to take any action or provide any service if the taking of such action or provision of such service would result in loss of the tax-exempt status of any Local Furnishing Bonds. In the event a Transmission Owner is ordered to take an action on behalf of a Customer that results in the loss of tax-exempt status of any Local Furnishing Bonds, such Customer shall be obligated to pay to the Transmission Owner all costs associated with the loss of tax-exempt status of the Local Furnishing Bonds.

14.3 LIPA and NYPA Tax Exempt Obligations

This provision is applicable to LIPA and NYPA, which have financed transmission facilities with the proceeds of tax-exempt bonds issued pursuant to the Internal Revenue Code. Notwithstanding any other provision of the ISO OATT or the ISO Services Tariff, neither the ISO nor the Transmission Owner shall be required to provide transmission service to any Customer pursuant to an ISO Tariff if the provision of such Transmission Service would result in loss of tax-exempt status of the NYPA Tax Exempt Bonds or LIPA Tax Exempt Bonds or impair LIPA's or NYPA's ability to issue future tax-exempt obligations. If, by virtue of an order issued by the Commission pursuant to Section 211 of the FPA, the ISO or a Transmission Owner is required to provide Transmission Service that would adversely affect the tax-exempt status of the LIPA Tax Exempt Bonds or NYPA's Tax-Exempt Bonds or any other tax-exempt debt obligations, then the Customer receiving such Transmission Service will compensate LIPA or NYPA for all costs, if any, associated with the loss of tax-exempt status plus the normal costs of Transmission Service.

14.4 Amendments

Nothing contained in the ISO Services Tariff or any Service Agreement shall be construed as affecting in any way the right of the ISO or a Transmission Owner under the ISO/TO Agreement to make application to the Commission for a change in: rates, terms, conditions, charges, or classifications of service; the provision of Ancillary Services; a Service Agreement; or a rule or regulation, under the FPA and pursuant to the Commission's rules and regulations promulgated thereunder.

Nothing contained in the ISO Services Tariff or any Service Agreement shall be construed as affecting in any way the ability of any Transmission Customer or Transmission Owner to exercise its rights under the FPA including, but not limited to, the right to file a complaint under Section 206 of the FPA or any successor statute and pursuant to the

Commission's rules and regulations promulgated thereunder.

Notwithstanding any other provision of the ISO Services Tariff, the ISO Services Tariff may be amended only in accordance with the ISO Agreement, the ISO/TO Agreement, and consistent with the requirements of the FPA and the Commission's rules and regulations promulgated thereunder.

14.5 Applicable Law And Forum

The ISO Services Tariff and any Service Agreement shall be governed by and construed in accordance with the law of the State of New York, except its conflict of law provisions. Customers irrevocably consent that any legal action or proceeding arising under or relating to the ISO Services Tariff or any Service Agreement shall be brought in any court of the State of New York or any federal court of the United States of America located in the State of New York. Customers irrevocably waive any objection that they may now or in the future have to the designated courts in the State of New York as the proper and exclusive forum for any legal action or proceeding arising under or relating to the ISO Services Tariff or any Service Agreement.

14.6 Counterparts

Any Service Agreement entered into pursuant to the ISO Services Tariff may be executed in several counterparts, each of which shall be an original and all of which shall constitute one and the same instrument.

14.7 Waiver

No delay or omission in the exercise of any right under a Service Agreement or the

ISO Services Tariff shall impair any such right or shall be taken, construed or considered as a waiver or relinquishment thereof, but any such right may be exercised from time-to-time and as often as may be deemed expedient. If any obligation or covenant under a Service Agreement or the ISO Services Tariff shall be breached and thereafter waived, such waiver shall be limited to the particular breach so waived and shall not be deemed to waive any other breach hereunder or under a Service Agreement.

14.8 Assignment

Obligations under the ISO Services Tariff and any Service Agreement shall be binding on the successors and assigns of the Service Agreement. No assignment shall relieve the original Customer from its obligations under the ISO Services Tariff or any Service Agreement.

14.9 Representations, Warranties & Covenants

A Service Agreement entered into under the ISO Services Tariff shall contain representations, warranties and covenants, as the parties deem appropriate and in accordance with the pro forma Service Agreement, regarding the Customer's ability to perform, and the enforceability of, the Service Agreement.

Rate Schedule 1

Market Administration and Control Area Services Charge

1. Parties to Which Charges Apply

The ISO shall charge and each Customer taking service under the ISO Services Tariff shall pay the Market Administration and Control Area Services charge on all services provided under the Tariff. Each Market Participant that sells or purchases Energy, including Demand Side Resources, sells or purchases Capacity, or provides Ancillary Services in the ISO Administered Markets utilizes Market Services and must enter into a Service Agreement under the Tariff, as set forth in Attachment A; and 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, and must enter into a Service Agreement under this Tariff, as set forth in Attachment A.

2. Billing

The ISO shall charge each Customer based on the product of: (i) the Market Administration and Control Area Services charge rate; and (ii) the Customer's billing units for the month. The billing units will be based on the Actual Energy Withdrawals for all Transactions to supply Load in the NYCA and all other purchases from the LBMP Markets to supply Load outside the NYCA.

3. Computation of Rate

The Market Administration and Control Area Services charge shall be computed on a monthly basis based on information available from the prior month. The charge shall equal the quotient of the ISO's monthly costs and expenses that are charged to the ISO Services Tariff divided by the total amount of Actual Energy Withdrawals to supply Load in the NYCA and all other purchases from the LBMP Markets to supply Load outside the NYCA, adjusted for revenues related to Installed Capacity deficiency penalties.

4. ISO Costs

ISO costs to be recovered through this charge shall include costs incurred by the ISO that are directly assignable to the services provided by the ISO under the Tariff and are not recoverable under Rate Schedule 1 of the ISO OATT. Costs recoverable under this charge shall include costs related to: the ISO's administration of the LBMP Markets; the ISO’s administration of Installed Capacity requirements and an Installed Capacity Market; the ISO's administration of Control Area Services, other than Ancillary Services provided under the ISO OATT; the ISO’s administration of the Market Power Monitoring Program; and other activities related to the maintenance of reliability in the NYCA.

Where costs or expenses or receipts are incurred on a basis other than a monthly basis, the ISO shall use reasonable judgment consistent with commonly accepted accounting practices to develop the monthly components.

Rate Schedule 2

Payments for Supplying Voltage Support Service

This rate schedule applies to payments to Suppliers who provide Voltage Support Service to the ISO. Transmission Customers will purchase Voltage Support Service from the ISO under the ISO OATT.

The embedded cost calculation methodology provided in this rate schedule shall be used to calculate payments to all eligible Suppliers providing Voltage Support Service as applied on a resource-specific basis. The ISO shall calculate and make payments monthly.

1.0 Responsibilities

The ISO shall coordinate the Voltage Support Service provided by Suppliers that qualify to provide such services as described in Section 1.1 of this Rate Schedule. The ISO shall also establish methods and procedures for Reactive Power (MVAr) capability testing.

1.1 Suppliers

To qualify for payments, Suppliers of Voltage Support Service shall provide a resource that has an AVR and has successfully performed Reactive Power (MVAr) capability testing in accordance with the ISO Procedures and prevailing industry standards. The ISO may direct Suppliers to operate their resources within these demonstrated reactive capability limits. Suppliers of Voltage Support Service will test their resources and provide these services in accordance with ISO Procedures.

Voltage Support Service includes the ability to produce or absorb Reactive Power within the resource's tested reactive capability, and the ability to maintain a specific voltage level under both steady-state and post-contingency operating conditions subject to the limitations of the resource's stated reactive capability.

2.0 Payments

Suppliers whose resource(s) meet the requirements to supply Installed Capacity, as described in Article 5 of the ISO Services Tariff, and are under contract to supply Installed Capacity shall receive one-twelfth the annual embedded cost payment for Voltage Support Service except as noted below with respect to Non-Utility Generators. To the extent suppliers of Installed Capacity are electrically located outside the NYCA, payments for Voltage Support Service will be subject to criteria established by the ISO.

Suppliers whose Generators are not under contract to supply Installed Capacity and Suppliers with synchronous condensers shall receive one-twelfth the annual embedded cost payment pro-rated by the number of hours that Generator or synchronous condenser operated in that month, as recorded by the ISO.

For Non-Utility Generators that are operating under existing power purchase agreements, the entity that is purchasing Energy and/or Capacity under such agreement or providing Transmission Service under that agreement shall be contacted by the ISO when the ISO requires Voltage Support Service from the contracted Resource. The ISO shall pay holders of the contracts for such resources, which are operating under existing power purchase agreements, the product of the average $/MVAr rate for the ISO and the MVAr capacity of the Non-Utility Generator as described below. At such time as the existing power purchase agreements are terminated or expire, the Non-Utility Generators may then supply the required embedded cost data to the ISO and then receive payments under this rate schedule.

(a) Formula for Determining the Payment for Voltage Support Service

Payments to Generators and synchronous condensers eligible to provide Voltage Support Service will be based upon amounts filed in FERC Form 1 (or equivalent) according to the following formula:

Annual VSCP = AFCR x VCAPCOST + VOM

Where:

Annual VSCP = Annual Voltage Support Service payment to resources

AFCR = Annual fixed charge rate associated with resource capital investment

VCAPCOST = Current capital investment of the resource allocated for supplying Voltage Support Service.

VOM = Operating and maintenance (O&M) expenses for supervision and engineering allocated for supplying Voltage Support Service:

(1) for Generators: O&M expenses (from FERC Form 1, Account #500 and 510, 517 and 528, 535 and 541, or 546 and 551) multiplied by 30% x (1-PF) as defined below.

(2) for synchronous condensers: O&M expenses (from applicable FERC Form 1 Accounts or equivalent).

VCAPCOST is defined as:

(1) for Generators:

VCAPCOST = [(1-PF) x 30% x VTG] + [10% x VACC] +0.2% x TOTREM

(2) for synchronous condensers:

VCAPCOST = Current capital investment of synchronous condenser equipment in Commission generation accounts or their equivalent (which are not already included in transmission rate base).

Where:

PF = Generator's tested power factor for producing Reactive Power (MVAr) at its normal maximum operating capability or 90% of its DMNC, whichever is greater.

VTG = Current capital investment of Generator's turbine-generator equipment from FERC Form 1, Account #314, 323, 333, or 344.

VACC = Current capital investment or Generator's accessory electrical equipment form FERC Form 1, Account #315, 324, 334, or 345.

TOTREM = Current total capital investment of production equipment (from FERC Form 1 (or equivalent), Account #310 through 346) Less ((1-PF) x 30% x VTG) Less (10% x VACC).

NOTE: The last term in the equation above (0.2% x TOTREM) is to account for Real Power Losses in the Generator step-up transformer associated with the production of full Reactive Power (MVAr) output.

Figure 2.0(a) illustrates the method for calculating the charge for Voltage Support Service

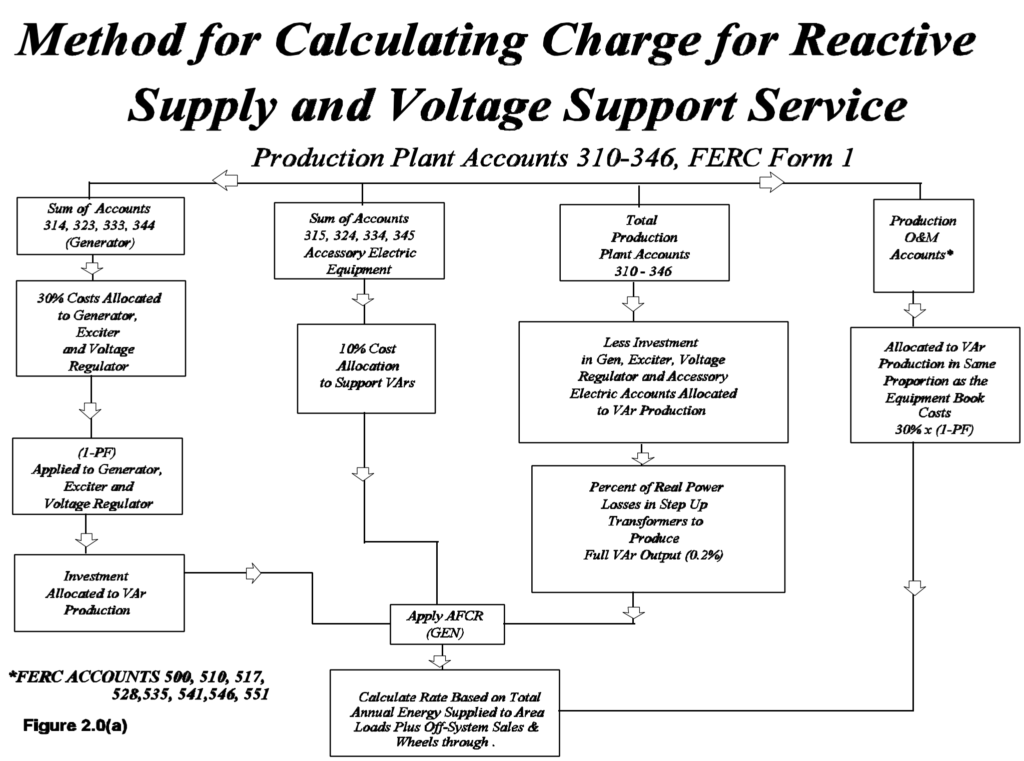


Figure 2.0(a)

using FERC Form 1 data.

(b) Lost Opportunity Costs

A Supplier of Voltage Support Service from a Generator that is being dispatched by the ISO shall also receive a payment for Lost-Opportunity Costs ("LOC") when the ISO directs the resource to reduce its real power (MW) output below its schedule in order to allow the resource to produce or absorb more Reactive Power (MVAr). The Lost-Opportunity Cost payment shall be calculated as the product of: (a) the MW of output reduction; (b) the time duration of reduction in hours or fractions thereof; and (c) the Real-Time LBMP at the Generator bus minus the Generator's Energy Bid for the reduced output of the Generator. The details of the lost opportunity payments are as follows:

The formula below describes the calculation of LOC as applied to each Resource supplying Voltage Support Service.

$$LOC = P_{RT}(D_1 - D_2) - \int_{D_2}^{D_1} Bid$$

Where:

P_{RT} = Real-Time LBMP

D_1 = Original dispatch point

D_2 = New dispatch point

Bid = Bid curve or Generation supplying Voltage Support Service

Figure 2.0(b) below graphically portrays the calculation of the LOC for a Generator which reduced its MW output to allow it to produce or absorb more Reactive Power (MVAr).

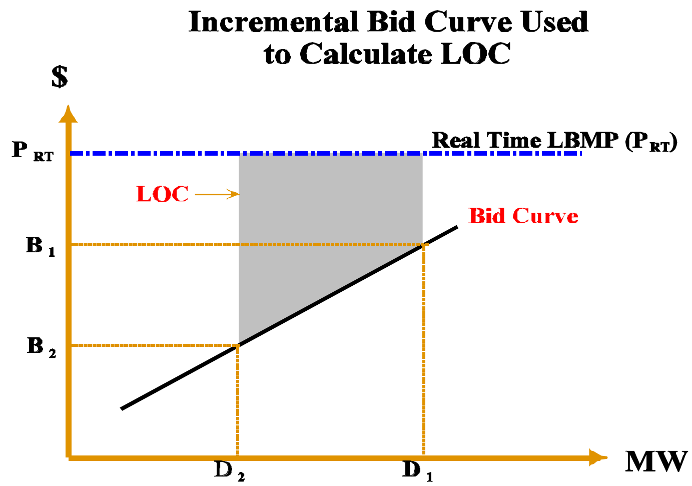


Figure 2.0(b)

(c) Payments for Voltage Support Service Provided by Non-Utility Generators

The ISO shall compute the rate used to calculate the payments to holders of power purchase agreements from Non-Utility Generators which provide Voltage Support Service based on forecast data using the following equation:

$$Rate_{VSS} = \frac{\sum^{All} NYISO_{VSSPayments} + PYA_{VSS}}{\sum^{All} RPCAP_{VSSPayments}}$$

Where:

$Rate_{VSS}$ = Average Annual $/MVAr rate for ISO Payments to Suppliers of Voltage Support Service

$\sum^{All} RPCAP_{VSSPayments}$ = The sum of the tested Reactive Power production capability for those resources providing Voltage

Support Service to the ISO.

$\sum^{All} NYISO_{VSSPayments}$ = The sum of the projected ISO payments to Suppliers providing Voltage Support Service including; (1) total annual embedded costs eligible for payment as defined in paragraph 2(a) of this Rate Schedule; (2) any applicable LOC to provide Voltage Support Service as defined in paragraph 2(b) of this Rate Schedule.

PYA_{VSS} = Total of prior year payments to Suppliers of Voltage Support Service less the total of payments received by the ISO from Transmission Customers and LSEs in the prior year for Voltage Support Service (including all payments for penalties).

The ISO shall pay each holder of a contract for a Non-Utility Generator operating under an existing power purchase agreement which provides Voltage Support Service the product of: (a) one-twelfth of the average annual $/MVAr rate for ISO payments to Suppliers of Voltage Support Service; (b) the lesser of the tested Reactive Power production capability (MVAr) of the Non-Utility Generator or the contract MVAr capability; and (c) for only those Non-Utility Generators that are not providing Installed Capacity under contract, the number of hours in the month the Non-Utility Generator provided Voltage Support Service divided by the number of hours in the month; and for those Non-Utility Generators that are under contract for Installed Capacity, (d) shall not apply. The ISO shall calculate and make payments monthly.

(d) Failure to Perform by Suppliers

A resource will have failed to provide voltage support if it:

(1) fails at the end of 10 minutes to be within 5% (+/-) of the requested Reactive Power (MVAr) level of production or absorption as requested by the ISO or applicable Transmission Owner for levels below the resource's Normal Operating limit which must be at least 90% of its Dependable Maximum Net Capability (DMNC).

(2) fails at the end of 10 minutes to be at 95% or greater of the resource's demonstrated reactive power capability (tested at its Normal Operating Limit or at 90% of its DMNC, whichever is greater in MW) in the appropriate lead or lag direction when requested to go to maximum lead or lag reactive capability by the ISO or applicable Transmission Owner.

Whether the resource has failed to provide Voltage Support in a contingency shall be defined by ISO Procedures. Suppliers of Voltage Support Service that fail to comply with the ISO Procedures will be assessed charges by the ISO as follows:

(e) Failure to Respond to ISO's Request for Steady-State Voltage Control

Initial Failure: If a resource fails to comply with the ISO’s request for steady-state voltage control, the ISO shall withhold Voltage Support Service payments from the non-complying Supplier equivalent to one-twelfth (1/12th) of the annual embedded cost payment for that specific resource (or an amount equal to the last month's voltage support payment made to that resource, if the resource is not an Installed Capacity provider). The Supplier shall also be liable for any additional cost in procuring replacement Voltage Support Service including LOC incurred by the ISO as a direct result of the Supplier’s non-performance.

Repeated Failures: For each instance of failure to perform, the non-complying Supplier will be subject to the charges described herein. If a resource fails to comply with the ISO's request on three (3) separate days, within a thirty (30) day period, then upon the third occurrence, the non-complying Supplier will no longer be eligible for Voltage Support Service payments for service provided by that resource. The ISO may reinstate payments once the Supplier complies with the following conditions to the ISO's satisfaction:

(1) the Supplier's resource must successfully perform a Reactive Power (MVAr) capability test, and

(2) the resource must provide Voltage Support Service for thirty (30) consecutive days without any compliance failures. No payments for Voltage Support Service or LOC will be made to the Supplier during this period.

(f) Failure to Provide Voltage Support Service When a Contingency Occurs on the NYS Power System

If a Supplier's resource fails to respond to a Contingency, based on ISO review and analysis, the ISO shall withhold Voltage Support Service payments from the non-complying Supplier as follows:

Initial Failure: The ISO will withhold from the Supplier one-twelfth (1/12th) of the annual embedded cost payment for the specific resource (or an amount equal to the last month's voltage support payment made to that resource, if the resource is not an Installed Capacity provider).

Second Failure within the same thirty (30) day period: The ISO shall withhold from the Supplier one-fourth (1/4th) of the annual embedded cost payment for the specific resource (or an amount equal to the last three (3) months' voltage support payments made to that resource, if the resource is not an Installed Capacity provider). In addition, the Supplier that is in violation shall be prohibited from receiving Voltage Support Service payments for the non-complying resource until the Supplier complies with the following conditions to the ISO's satisfaction:

(1) the Supplier's resource shall successfully perform a Reactive Power (MVAr) capability test, and

(2) the resource shall provide Voltage Support Service for thirty (30) consecutive days without any compliance failures. No payments for Voltage Support Service, or LOC shall be made to the Supplier during this period.

Rate Schedule 3

Payments for Regulation Service

This Rate Schedule applies to Suppliers who provide Regulation Service to the ISO. Transmission Customers will purchase Regulation Service from the ISO under the ISO OATT.

1.0 Obligations of the ISO and Suppliers

1.1 The ISO shall:

(a) Establish regulation and frequency response criteria and requirements in the ISO Procedures to ensure that Generators follow changes in Load consistent with the Reliability Rules;

(b) Provide SCD Base Point Signals and AGC Base Point Signals to Generators providing this Service to direct the Generator's output;

(c) Establish criteria in the ISO Procedures that Generators must meet to qualify to supply this Service;

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

(e) Select Suppliers to provide this Service in the Day-Ahead Market and during the Dispatch Day ("Real-Time Market"), as described in Section 2.0 of this Rate Schedule;

(f) Pay Suppliers for providing this Service as described in Section 4.0 of this Rate Schedule; and

(g) Monitor the Suppliers' performance to ensure that they provide Regulation Service as required, as described in Section 3.0 of this Rate Schedule.

1.2 Suppliers shall:

(a) Use Generators that are able to respond to AGC Base Point Signals sent by the ISO pursuant to the ISO Procedures;

(b) Not use, contract to provide, or otherwise commit the capability that is designated to provide Regulation Service to provide Energy or spinning reserve to any party other than the ISO; and

(c) Pay all charges due under Sections 2(f) and 4.1 of this Rate Schedule.

1.3 Generators shall:

(a) Comply with SCD Base Point Signals issued by the ISO at all times pursuant to the ISO Procedures; and

(b) Comply with the ISO Procedures that apply to providing Regulation Service

2.0 Selection of Suppliers in the Day-Ahead and Real-Time Market (Dispatch Day)

(a) The ISO shall select Suppliers, in the Day-Ahead Market, to provide Regulation Service for each hour in the following Dispatch Day, from those that have Bid to provide Regulation Service from Generators that meet the qualification standards and criteria established in the ISO Procedures.

(b) Real-Time Market: The ISO shall establish a Real-Time Market to provide an alternate supply for Regulation Service during the Dispatch Day where (i) Suppliers scheduled in the Day-Ahead Market are inadequate (e.g., insufficient Suppliers Bid into the Day-Ahead Market for Regulation Service), (ii) a scheduled Supplier is unable to provide Regulation Service (e.g., the Generator tripped), or (iii) the demand for Regulation Service increases beyond the scheduled supply. The ISO shall select Suppliers in the Real-Time Market, during the Dispatch Day, to provide Regulation Service for each hour in which an insufficient supply of Regulation Service exists. The ISO shall select Suppliers for Regulation Service from those that have Bid to provide Regulation Service from Generators that meet the qualification standards and criteria established in the ISO Procedures.

(c) The ISO shall establish separate Availability market clearing prices for Regulation Service in the Day-Ahead and Real-Time Market.

(d) Bidding Process: (i) Any qualified Supplier may submit a Bid in the Day-Ahead Market to provide this Service; (ii) Bids rejected by the ISO may be modified and resubmitted by the Supplier to the ISO in accordance with the terms of the ISO Tariff; and (iii) Bids in the Day-Ahead Market that are not accepted by the ISO shall be automatically considered for the Real-Time Market, unless withdrawn by the Supplier.

(e) Each Bid shall contain the following information: (i) the Generator capability (in MW) that the Supplier will provide for Regulation Service; (ii) the Generator's regulation response rate (in MW/Minute) which must be sufficient to permit that Generator to provide the offered amount of Regulation Service within an SCD interval of normal length (initially, SCD intervals will normally be five (5) minutes long); (iii) the Supplier's Bid Price (in $/MW); and (iv) the physical location and name or designation of the Generator.

(f) The ISO shall, if a Generator providing Regulation Service trips off line, immediately attempt to re-establish a supply for the remainder of that Generator's commitment. Any additional cost incurred by the ISO as a result of covering the defaulting Generator's remaining commitment shall be reimbursed to the ISO by the defaulting Supplier. If the Availability payment for the replacement Regulation Service decreases, the ISO shall not pay the defaulting Supplier the difference in cost.

(g) If a Generator reduces its capacity bid subsequent to being scheduled to provide Regulation or Operating Reserves (either Day-Ahead or in a Supplemental Commitment), and if it, as a result, can no longer provide both the amount of Energy it was scheduled to provide Day-Ahead and the amount of Regulation and Operating Reserves it was scheduled to provide, the ISO will first reduce the amount of Operating Reserves it is scheduled to provide, and then will reduce the amount of Regulation it is scheduled to provide, until the total amount of Energy, Regulation and Operating Reserves it is scheduled to provide is equal to its capacity (or until it is no longer scheduled to provide Regulation or Operating Reserves).

3.0 Monitoring Suppliers and Generators

(a) The ISO shall establish (i) Generator performance measurement criteria and (ii) procedures to disqualify Suppliers using Generators that consistently fail to meet such criteria.

(b) The ISO shall establish and implement a Performance Tracking System to monitor the performance of Generators that provide Regulation Service. The ISO shall develop performance indices as part of the ISO Procedures. The Performance Tracking System shall compute the difference between the Energy actually supplied and the Energy scheduled by the ISO for all Generators serving Load within the NYCA as set forth in the ISO Procedures. The ISO shall use these values to compute Settlements.

(c) Payments by the ISO to each Supplier of Regulation Service will be based in part on the Generator's performance with respect to the performance indices.

4.0 Payments to Suppliers of Regulation Services

(a) The ISO shall pay Suppliers of this Service (i) an Availability payment (for reserving capability to provide Regulation Service), and (ii) an Energy payment, as described below.

(b) The Availability payment, for each hour or fraction thereof in which Regulation Service is provided, is equal to t h e

following:

$$Availability\ Payment = MCP_{reg}\ x\ R_{cap}$$

Where:

MCP_{reg} is the applicable regulation market clearing price for regulation capability (in MW), in either the Day-Ahead or Real-Time Market, as appropriate, as established by the ISO; and R_{cap} is the regulation capability (in MW) offered by the Supplier and selected by the ISO for either the Day-Ahead or Real-Time Market.

If Suppliers are scheduled in the Real-Time Market to begin providing Regulation Service at some point within an hour, the market clearing price determined in the Real-Time Market may change during the hour. All Suppliers scheduled in the Real-Time Market to provide Regulation Service during the portion of any such hour preceding the price change will be paid the market clearing price determined in the Real-Time Market for the portion of the hour preceding the price change. All Suppliers scheduled in the Real-Time Market to provide Regulation Service during the portion of any such hour following the price change will be paid the market clearing price determined in the Real-Time Market for the portion of the hour following the price change.

The Energy payment is equal to the following:

(i) Each Supplier shall receive Day-Ahead Market payments for Energy consistent with that Supplier's Day-Ahead schedule.

(ii) At times when the AGC Base Point Signals exceeds the SCD Base Point Signals sent to a

Supplier's resource, that Supplier shall be paid the Real-Time LBMP at that resource's bus for all Energy produced by that resource, up to the amount of Energy scheduled by the AGC Base Point Signals, minus the amount of Energy scheduled Day-Ahead to be produced by that resource.

(iii) At times when the SCD Base Point Signals exceeds the AGC Base Point Signals sent to a Supplier's Generator, each Supplier shall be paid the Real-Time LBMP at the Generator's bus for X MW minus the amount of Energy scheduled Day-Ahead to be produced by that Generator, where X is defined as:

$$X = \begin{cases} ACT, \text{ if } ACT < AGC-(SCD-AGC); \\ AGC-(SCD-AGC)+2(ACT-(AGC-(SCD-AGC))), \\ \qquad \text{if } ACT \geq AGC-(SCD-AGC) \text{ and } ACT \leq AGC; \\ SCD, \text{ if } ACT > AGC; \end{cases}$$

where *ACT* is the amount of Energy actually produced by the Generator; *AGC* is the AGC Base Point Signal sent to the Generator; and *SCD* is the SCD Base Point Signal sent to the Generator.

(iv) Notwithstanding the preceding clauses, whenever the ISO announces a reserve pick-up, each Supplier located in the area affected by that reserve pick-up shall be paid the Real-Time LBMP for all Energy it produces, minus the amount of Energy scheduled to be produced Day-Ahead by that Generator, if that Supplier was either scheduled to operate in BME or subsequently has been directed to operate by the ISO.

Regulation Market Clearing Price

The ISO shall determine a regulation market clearing price to be paid to Suppliers for resource Availability (in MW) reserved to provide Regulation Service in the Day-Ahead or Real-Time Markets. The ISO shall stack Bids submitted by qualified Suppliers from lowest Bid ($/MW) to highest Bid. The ISO shall select Bids to provide Regulation Service starting with the lowest Bids.

The Bid associated with the last Supplier selected to supply Regulation Service shall set the MCP_{reg}. All Suppliers selected in the same market (i.e., Day-Ahead or Real-Time) will receive an Availability payment calculated with the corresponding MCP_{reg}.

4.1 Payments by Suppliers

Suppliers shall pay to the ISO a charge as follows:

Supplier Charge = Energy Deviation x MCP x (Length of SCD Interval/60 minutes)

where: Energy Deviation (in MW) is the absolute difference between the actual Energy supplied by the Supplier and the Energy required by the AGC Base Point Signals, whether positive or negative, averaged over each SCD interval; MCP is the market clearing price ($/MW) which applies to the SCD interval for this Service in the Real-Time Market or the Day-Ahead Market if no Real-Time Market applies.

The method used by the ISO to calculate the Energy Deviation will permit Suppliers a certain period of time to respond to AGC Base Point Signals. Initially this time period will be thrity (30) seconds, although the ISO will have the authority to change its length. If the Supplier's output at any point in time is between the largest and the smallest of the AGC Base Points sent to that Supplier within the preceding thirty (30) seconds (or such other time period length as the ISO may define), the Supplier's Energy Deviation at that point in time will be zero. Otherwise, the Supplier may have a positive Energy Deviation. However, in cases in which responding to the AGC Base Point within that time period would require a Supplier to change output at a rate exceeding the amount of Regulation it has been scheduled to provide, the Supplier will have a zero Energy Deviation if it changes output at the rate equal to the amount of Regulation it is scheduled to provide.

4.2 Payments by Generators not providing Regulation Service

Generators that sell Energy through the LBMP Markets or supply Bilateral Transactions that serve Load in the NYCA, but do not provide Regulation Service, shall pay to the ISO a charge for Regulation Service equivalent to the following:

Generator Charge = Energy Difference x MCP x Length of SCD Interval/60 minutes where: Energy Difference (in MW) is the absolute difference between the actual Energy supplied by the Generator and the Energy required by the SCD Base Point Signals, whether positive or negative, averaged over each SCD interval for Regulation Service in the Real-Time Market applies. In cases in which the Energy Difference that would be calculated using the procedure described above is less than a tolerance level to be defined by the ISO, the ISO shall set the Energy Difference for that SCD interval equal to zero.

Rate Schedule 4

Payments for Supplying Operating Reserves

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

The ISO shall provide procedures to establish adequate Operating Reserves that comply with the Reliability Rules. Operating Reserves are classified as follows:

(1) Spinning Reserve: Operating Reserves provided by generation facilities and Interruptible Load Resources located within the NYCA that are already synchronized to the NYS Power System and can respond to instructions to change output level within ten (10) minutes;

(2) 10-Minute Non-Synchronized Reserve ("10-Minute NSR"): Operating Reserves provided by generation facilities that can be started, synchronized and loaded within ten (10) minutes; and

(3) 30-Minute Reserve: Operating Reserves provided by generation facilities and Interruptible Load Resources that can respond to instructions to change output or consumption level within thirty (30) minutes.

The ISO shall satisfy at least fifty (50) percent of the applicable 10-Minute Reserve requirements with Spinning Reserve. If the ISO satisfies all of the 10-Minute Reserve requirement through Spinning Reserve, it does not have to maintain 10-Minute NSR. The ISO shall establish additional categories of Operating Reserves if necessary to ensure reliability.

1.0 General Requirements

The ISO shall ensure that providers of Operating Reserves are properly located electrically so that transmission constraints resulting from either commitment or dispatch of units do not limit the ability to deliver Energy to Loads in the case of a Contingency. The ISO will ensure that Capacity counted toward meeting Operating Reserve requirements is not also counted toward meeting Regulation and Frequency Response Service requirements.

2.0 Spinning Reserve-Requirements and Responsibilities

2.1 Day-Ahead Market for Spinning Reserve

Suppliers offering Generator or Demand Side Resources to provide Spinning Reserve in the Day-Ahead commitment shall submit Availability Bids of each hour of the upcoming day. The ISO shall select Spinning Reserve Suppliers for each hour of the upcoming day through its Day-Ahead commitment, using Bids and/or schedules provided by the Suppliers, including Availability Bids by both Class A Unit and Class B Unit Suppliers, and Energy Bids by Class A Unit Suppliers. The ISO shall notify each Supplier of Spinning Reserve that has been selected in the Day-Ahead Schedule of the amount of Spinning Reserve it has been scheduled to provide. Suppliers of Spinning Reserve scheduled Day-Ahead shall either provide Spinning Reserve or shall generate Energy when requested by the ISO to do so, in all hours for which they have been selected to provide Spinning Reserve.

2.2 Real-Time Market for Spinning Reserve

During each Dispatch Day, Suppliers whose Generators have not been scheduled to provide Spinning Reserve and which still have Capacity that has not been committed for use in any other way may submit Availability Bids to provide Spinning Reserve to the ISO. These Real-Time Availability Bids may differ from Availability Bids that were made by those Suppliers in the

Day-Ahead commitment. If the ISO anticipates that it will require additional Spinning Reserves in an hour, it shall select additional Suppliers of Spinning Reserve from among those Suppliers that have submitted Real-Time Availability Bids to it for that hour. It shall make this selection with the objective of minimizing the cost of meeting load and providing all necessary Ancillary Services in that hour. The ISO shall notify each Supplier of Spinning Reserve that has been selected in the Real-Time dispatch of the amount of Spinning Reserve it must provide. Any previously uncommitted Class A Unit whose Bid to provide Spinning Reserve is accepted by the ISO will be treated as a Generator on dispatch.

2.3 Suppliers' Responsibilities

All Generators selected by the ISO as suppliers of Spinning Reserve must be located within the NYCA and must be under ISO control. All Suppliers of Spinning Reserves selected by the ISO shall ensure that their Generators maintain and deliver the appropriate quantity of Energy when called upon by the ISO in all hours in which they have been selected to provide Spinning Reserve. All Demand Side Resources selected by the ISO as Suppliers of Spinning Reserve shall reduce consumption of the appropriate quantity of Energy when called upon by the ISO in all hours in which they have been selected to provide Spinning Reserve. Each Generator bidding to supply Spinning Reserve must be able to provide Energy consistent with the Reliability Rules and the ISO Procedures when called upon by the ISO and shall specify in its Bid the amount of time for which it can supply such Energy. Each Demand Side Resource bidding to supply Spinning Reserve must be able to reduce consumption of Energy consistent with the Reliability Rules and consistent with the ISO Procedures when called upon by the ISO and shall specify in its Bid the amount of time for which it can reduce consumption of Energy.

Class A Units may not use contracts to provide or otherwise commit any Capacity that has been scheduled to operate or to provide Operating Reserves, in either the Day-Ahead commitment or any supplemental commitment conducted by the ISO. They also may not increase the Energy Bids made for the portions of those Generators that have been scheduled Day-Ahead to provide Spinning Reserve. They may enter into alternate sales arrangements utilizing any Capacity that has not been scheduled to operate or to provide Operating Reserves. Class B Units may not use, contract to provide or otherwise commit any Capacity that has been scheduled to provide Spinning Reserve, in either the Day-Ahead commitment or in any subsequent commitment by the ISO. Subject to the limitations on Installed Capacity Suppliers, if applicable, they may enter into alternate sales arrangements utilizing any Capacity that has not been scheduled to provide Spinning Reserve.

2.4 Spinning Reserve Service in Real-Time Operation

The ISO shall, if necessary, reduce the output on Class A Units via SCD from otherwise economic loading to provide Spinning Reserve capability. When reserve is activated, the ISO shall measure actual performance against expected performance and shall charge financial penalties, as detailed in Section 5 of this Rate Schedule, to Suppliers of Spinning Reserve which fail to perform in accordance with their accepted bids.

3.0 10-Minute NSR and 30-Minute Reserve Requirements and Responsibilities

3.1 Day-Ahead Market for 10-Minute NSR and 30-Minute Reserve

Suppliers offering Generators or Demand Side Resources to provide 10-Minute NSR and/or 30-Minute Reserve in the Day-Ahead commitment shall submit availability Bids for each hour of the upcoming day. The ISO shall select Suppliers of 10-Minute NSR and 30-Minute Reserve for each hour of the upcoming day through the Day-Ahead commitment, using Bids and/or schedules provided by the Suppliers. The ISO shall notify each Supplier of 10-Minute NSR and/or 30-Minute Reserve that has been selected in the Day-Ahead schedule of the amount of 10-Minute NSR and/or 30-Minute Reserve it has been scheduled to provide.

Suppliers of 10-Minute NSR and/or 30-Minute Reserve scheduled Day-Ahead shall provide 10-Minute NSR and/or 30-Minute Reserve for all hours in which they have been scheduled to provide 10-Minute NSR and/or 30-Minute Reserve.

3.2 Real-Time Markets for 10-Minute NSR and 30-Minute Reserve

During the day, Suppliers that have not been scheduled to provide 10-Minute NSR or 30-Minute Reserve and which still have Capacity that has not been committed for use in any other way may submit Availability Bids to provide 10-Minute NSR and/or 30-Minute Reserve to the ISO. These Real-Time Availability Bids may differ from Availability Bids that were made by those Suppliers in the Day-Ahead commitment.

If the ISO anticipates that additional Suppliers of 10-Minute NSR or 30-Minute Reserve are needed in an hour, it shall select additional Suppliers of 10-Minute NSR or 30-Minute Reserve from among those Suppliers that have supplied Real-Time Availability Bids to it for that hour. It shall make this selection with the objective of minimizing the cost of meeting Load and providing all necessary Ancillary Services in that hour.

The ISO may perform multiple selections of Suppliers of 10-Minute NSR or 30-Minute Reserve for any given hour. Suppliers bidding to supply 10-Minute NSR or 30-Minute Reserve that have not already been scheduled to provide 10-Minute NSR or 30-Minute Reserve may change their Real-Time Bids from one hour to the next. The ISO shall notify each Supplier of 10-Minute NSR or 30-Minute Reserve that has been schedule in the Real-Time dispatch of the amount of 10-Minute NSR or 30-Minute Reserve it must provide. Any Supplier whose Bid to provide 10-Minute NSR or 30-Minute Reserve is accepted by the ISO in the Real-Time dispatch must make its Generators or Demand Side Resources available for dispatch by the ISO.

3.3 Suppliers' Responsibilities

Subject to the ISO's locational requirements, Suppliers of 10-Minute NSR or 30-Minute Reserve may use Generators located within the NYCA or outside the NYCA. In order for a Supplier to provide 10-Minute NSR or 30-Minute Reserve using a Generator located outside the NYCA, the operator of that Generator’s Control Area must have agreed to modify the DNI between the NYCA and that Control Area instantaneously upon notification by the ISO that the ISO is initiating a reserve pick-up for the area including that Generator. The amount of a 10-Minute NSR provided by Generators within any given external Control Area cannot exceed the maximum amount by which the operator of that Control Area will change the DNI from that Control Area into the NYCA within ten (10) minutes of the initiation of a reserve pick-up by the ISO. Likewise, the amount of 30-Minute Reserve provided by Generators within any given external Control Area cannot exceed the maximum amount by which the operator of that Control

Area will change the DNI from that Control Area into the NYCA within thirty (30) minutes of the initiation of a reserve pick-up by the ISO. All Generators selected by the ISO as Suppliers of 10-Minute NSR or 30-Minute Reserve shall ensure that their Generators maintain and deliver the appropriate quantity of Energy when called upon by the ISO in all hours in which they have been scheduled to provide 10-Minute NSR or 30-Minute Reserve.

Suppliers may not use, contract to provide or otherwise commit any Capacity on any Generator that has been scheduled to provide 10-Minute NSR or 30-Minute Reserve in the Day-Ahead commitment or in the Real-Time dispatch. Subject to the limitations on Installed Capacity Suppliers, if applicable, they may enter into alternate sales arrangements utilizing any Capacity that has not been scheduled to provide 10-Minute NSR or 30-Minute Reserve in either the Day-Ahead commitment or in the Real-Time dispatch.

3.4 10-Minute NSR and 30-Minute Reserve Service in Real-Time Operation

Suppliers of 10-Minute NSR and 30-Minute Reserve shall respond to direction by the ISO to activate. When reserve is activated, the ISO shall measure actual performance against expected performance and shall charge financial penalties, as detailed in Section 5 of this Rate Schedule, to Suppliers of 10-Minute NSR or 30-Minute Reserve which fail to perform in accordance with their accepted Bids.

4.0 Payments to Suppliers of Spinning Reserve

Availability Payments

Each Supplier which the ISO has scheduled Day-Ahead to provide Spinning Reserve shall be paid the Day-Ahead Availability price for Spinning Reserve in each hour, multiplied by the amount of Spinning Reserve that Supplier is scheduled to provide in each hour. The Day-Ahead Availability price for Spinning Reserve for each hour shall be equal to the highest Day-Ahead Availability Bid made by a Supplier that has been scheduled Day-Ahead to provide Spinning Reserve in that hour.

Subject to the limitation in Section 4.3 below, each Supplier whose Generator(s) provides more Spinning Reserve in an hour than it was scheduled Day-Ahead to provide in that hour shall be paid the Real-Time Availability price for Spinning Reserve in that hour, multiplied by the amount of Spinning Reserve that Supplier provided in that hour that was in excess of the amount scheduled to be provided Day-Ahead, if any. The ISO shall calculate separate Real-Time Availability prices for Spinning Reserve for each hour. The Real-Time Availability price for Spinning Reserve for each hour shall be equal to the highest Real-Time Availability Bid made by a Supplier providing Spinning Reserve in that hour that is providing more Spinning Reserve in that hour than it had been scheduled to provide in that hour in the Day-Ahead schedule.

Real-Time Availability Prices for Spinning Reserve may change within an hour, if additional Suppliers are scheduled to begin providing this Service within an hour. In such cases, the price changes will apply only to the remaining portion of that hour. All Suppliers providing Spinning Reserve that receive the Real-Time Availability price for Spinning Reserve will be paid the Real-Time Availability price applicable to the portion of the hour preceding the price change for all Spinning Reserve provided before the price change. All Suppliers providing Spinning Reserve that receive the Real-Time Availability price for Spinning Reserve will be paid the Real-Time Availability price applicable to the portion of the hour following the price change for all Spinning Reserve provided after the price change.

Acceptance of any Spinning Reserve Bid in the Real-Time Market shall not affect the Availability price for Spinning Reserve that was determined Day-Ahead.

Lost Opportunity Cost Payments

Suppliers of Spinning Reserve whose Class A Unit output in the Real-Time dispatch has been reduced for the purpose of creating Spinning Reserve will be paid for Lost Opportunity Costs. The Lost Opportunity Cost payment that each such Supplier receives shall be computed by multiplying the Marginal Lost Opportunity Cost ("MLOC") in each hour by the number of MW of Spinning Reserve supplied by that Supplier in that hour. MLOC shall be calculated as follows:

$$MLOC = \max_{ies} (P_i - B_i)$$

where:

B_i = Real-Time Energy Bid by Generator *i* at the level at which it is dispatched;
P_i = Real-Time LBMP at Generator *i*'s location; and
S = Set of Generators backed down to provide Spinning Reserve.

In cases where Spinning Reserve is bottled (meaning that there are active transmission Constraints on the locations at which Spinning Reserve can be supplied), MLOC will be calculated on a locational basis. Suppliers with Class B Units scheduled for Spinning Reserve shall not receive Lost Opportunity Cost payments.

Other Payments

The ISO shall pay the Real-Time LBMP for all Energy generated in accordance with the ISO's instructions by Suppliers of Spinning Reserve. (Suppliers of Spinning Reserve shall be paid for Energy produced during reserve pick-ups in accordance with the provisions of Article 4 of the Tariff relative to Real-Time Settlements.) Real-Time LBMPs shall be computed under the assumption that all Energy generated by Class B Units supplying Spinning Reserve are fixed injections. As provided in Article 4 of the Tariff, each Generator providing Spinning Reserves shall also be compensated by the ISO if its Bid Production Cost to produce the Energy the ISO has requested it to generate, including start-up costs, exceeds the revenues it receives from the sale of Energy at LBMP prices.

Payments to Suppliers of 10-Minute Non-Synchronized Reserve

Availability Payments

Each Supplier which the ISO has scheduled Day-Ahead to provide 10-Minute NSR shall be paid the Day-Ahead Availability price for 10-Minute NSR in each hour, multiplied by the amount of 10-Minute NSR that Generator is scheduled to provide in each hour. The Day-Ahead Availability price for 10-Minute NSR for each hour shall be equal to the highest Day-Ahead Availability Bid made by a Supplier that has been scheduled Day-Ahead to provide 10-Minute NSR in that hour.

Subject to the limitation in Section 4.3 below, each Supplier which provides more 10-Minute NSR than it was scheduled Day-Ahead to provide in that hour shall be paid the Real-Time Availability price for 10-Minute NSR, multiplied by the amount of 10-Minute NSR that Generator provided in that hour that was in excess of the amount scheduled to be provided Day-Ahead, if any. The ISO shall calculate separate Real-Time Availability prices for 10-Minute NSR for each hour. The Real-Time Availability price for 10-Minute NSR for each hour shall be equal to the highest Real-Time Availability Bid made by a Supplier providing 10-Minute NSR in that hour that is providing more 10-Minute NSR in that hour than it had been scheduled to provide in that hour in the Day-Ahead schedule.

Real-time Availability Prices for 10-Minute NSR may change within an hour, if additional Suppliers are scheduled to begin providing this Service within an hour. In such cases, the price changes will apply only to the remaining portion of that hour. All Suppliers providing 10-Minute NSR that receive the Real-Time Availability price for 10-Minute NSR will be paid the Real-Time Availability price applicable to the portion of the hour preceding the price change for all 10-Minute NSR provided before the price change. All Suppliers providing 10-Minute NSR that receive the Real-Time Availability Price for 10-Minute NSR will be paid the Real-Time Availability price applicable to the portion of the hour following the price change for all 10-Minute NSR provided after the price change.

Acceptance of any Supplier's Bid to supply 10-Minute NSR in the Real-Time Market shall not affect the Availability price for 10-Minute NSR that was determined Day-Ahead.

Other Payments

The ISO shall pay the Real-Time LBMP for all Energy generated in accordance with the ISO's instructions by Suppliers of 10-Minute NSR. (Suppliers of 10-Minute NSR shall be paid for Energy produced during reserve pick-ups in accordance with the provisions of Article 4 related to Real-Time Settlement.)

As provided in Article 4 of the Tariff, each 10-Minute NSR Supplier shall also be compensated by the ISO if its Bid Production Cost to produce the Energy the ISO has requested it to generate, including start-up costs, exceeds the revenues it receives from the sale of Energy at LBMP prices.

4.2 Payments to Suppliers of 30-Minute Reserve

Availability Payments

Each Supplier scheduled Day-Ahead to provide 30-Minute Reserve shall be paid the Day-Ahead Availability price for 30-Minute Reserve in each hour, multiplied by the amount of 30-Minute Reserve that the Supplier is scheduled to provide in each hour. The Day-Ahead Availability price for 30-Minute Reserve for each hour shall be equal to the highest Day-Ahead Availability Bid made by a Supplier that has been scheduled Day-Ahead to provide 30-Minute Reserve in that hour.

Subject to the limitation in Section 4.3 below, each Supplier which provides more 30-Minute Reserve than it was scheduled Day-Ahead to provide in each hour shall be paid the Real-Time Availability price for 30-Minute Reserve, multiplied by the amount of 30-Minute Reserve that the Supplier provided in that hour that was in excess of the amount scheduled to be provided Day-Ahead, if any. The ISO shall calculate separate Real-Time Availability prices for 30-Minute Reserve for each hour. The Real-Time Availability price for 30-Minute Reserve for each hour shall be equal to the highest Real-Time Availability Bid made by a Supplier providing 30-Minute Reserve in that hour that is providing more 30-Minute Reserve in that hour than it had been scheduled to provide in that hour in the Day-Ahead schedule. Real-time Availability prices for 30-Minute Reserve may change within an hour, if additional Suppliers are scheduled to begin providing this service within an hour. In such cases, the price changes will apply only to the remaining portion of that hour. All Suppliers providing 30-Minute Reserve that receive the Real-Time Availability price for 30-Minute Reserve will be paid the Real-Time Availability price applicable to the portion of the hour preceding the price change for all 30-Minute Reserve provided before the price change. All Suppliers providing 30-Minute Reserve that receive the Real-Time Availability price for 30-Minute Reserve will be paid the Real-Time Availability price applicable to the portion of the hour following the price change for all 30-Minute Reserve provided after the price change. Acceptance of any Bid to supply 30-Minute Reserve in the Real-Time Market shall not affect the Availability price for 30-Minute Reserve that was determined Day-Ahead.

Other Payments

The ISO shall pay the Real-Time LBMP for all Energy generated in accordance with the ISO's instructions by Suppliers of 30-Minute Reserve. (Suppliers of 30-Minute Reserve shall be paid for Energy produced during reserve pick ups in accordance with the provisions of Article 4 related to Real-Time Settlement.) As provided in Article 4 of the Tariff, each Supplier providing 30-Minute Reserve shall also be compensated by the ISO if its Bid Production Cost to produce the Energy the ISO has requested it to generate, including start-up costs, exceeds the revenues it receives from the sale of Energy at LBMP prices.

4.3 Exceptions

Notwithstanding anything to the contrary in this Rate Schedule, no payments shall be made to any Supplier providing Operating Reserves for reserves provided by that Supplier in excess of the amount of Operating Reserves scheduled by the ISO either Day-Ahead or in any subsequent schedule. The market clearing price paid to Suppliers of any category of Operating Reserve shall not be determined by any Bid to supply Operating Reserve that has not been accepted by the ISO.

5.0 Failure to Provide Operating Reserves

If a Supplier reduces its Capacity Bid subsequent to being scheduled to provide Regulation Service or Operating Reserves (either Day-Ahead or in a supplemental commitment), and if the ISO must, as a result, reduce the amount of Operating Reserves that Supplier is scheduled to provide in accordance with Rate Schedule 3 of this Tariff, the ISO will first reduce the amount of 30-Minute Reserve that Generator is scheduled to provide. If it is still necessary to reduce the amount of Operating Reserves that Supplier is scheduled to provide, the ISO will reduce the amount of 10-Minute NSR that Generator is scheduled to provide. Finally, if it is still necessary to reduce the amount of Operating Reserves that Supplier is scheduled to provide, the ISO will reduce the amount of Spinning Reserve that Generator is scheduled to provide.

If a Supplier scheduled Day-Ahead to provide Operating Reserves trips off-line and consequently is unable to provide Spinning Reserve, or if the amount of Operating Reserves a Supplier is scheduled to provide is decreased due to a reduction in that Supplier's capacity, it shall be charged the Real-Time Availability price (or the Day-Ahead Availability price, if there is no Real-Time Availability price) in each hour for the relevant category of Operating Reserves applied to the reduction in the amount of Operating Reserves it was scheduled Day-Ahead to provide. This reduction shall be calculated using a supply ratio which is the ratio of the amount of Energy the Operating Reserve Supplier actually provided in a pick-up to the amount of Energy it was dispatched to provide. In cases where there are multiple reserve pick-ups within a day, the average supply ratio calculated for the Supplier for pick-ups that occurred while it was a Suppliers of Operating Reserves will determine payments to that Supplier.

If the ISO calls for a Supplier of any category of Operating Reserves (other than a Supplier that has previously tripped off-line) to generate Energy with part or all of the Capacity that the ISO has scheduled to provide any category of Operating Reserves, and that Supplier fails to provide the amount of Energy requested by the ISO within the time applicable for the scheduled Operating Reserves (ten (10) or thirty (30) minutes), the ISO shall:

(1) not pay the non-performing Supplier for any shortfall in the amount of Energy provided;

(2) charge the Supplier for any shortfall in the amount of Energy provided, at the Real-Time LBMP for Energy at that Supplier's location;

(3) charge the Supplier a regulation penalty, as described in Rate Schedule 3; and

(4) reduce any Availability payments for the scheduled Operating Reserves, and any Lost Opportunity Cost payments, if applicable, that the Supplier would otherwise have received for the 24-hour billing period in which that Supplier failed to perform as scheduled. The Availability payments and the Lost Opportunity Cost payments, if applicable, that the Supplier would have received will be calculated by multiplying the lowest ratio of the amount of Energy supplied to the amount of Energy scheduled, during any activation of that Supplier during that 24-hour billing period by the applicable Availability payments and Lost Opportunity Cost payments, if applicable, that the Supplier would otherwise have received.

If a Generator providing Operating Reserves has repeatedly failed to provide Energy when called upon by the ISO, the ISO may preclude that Generator from providing Operating Reserves in the future. If a specific Generator has been precluded from supplying Operating Reserves, the ISO shall require that Generator to pass a re-qualification test before accepting any additional Bids to supply Operating Reserves from that Generator.

6.0 Self-Supply

Transactions may be entered into to provide for Self-Supply of Operating Reserves. Customers seeking to Self-Supply Operating Reserves must place the Generator(s) supplying any one of the Operating Reserves under ISO control. The Generator(s) must meet ISO rules for acceptability. The amount that any such Customer will be charged for Operating Reserves will be reduced by the market value of the services provided by the specified Generator(s) as determined in the ISO Services Tariff.

Rate Schedule 5

Payments For Black Start Capability

This Rate Schedule applies to payments to Suppliers who provide Black Start Capability Service to the ISO. The ISO shall make Black Start Capability payments only to those selected Suppliers that have appropriate Black Start equipment installed and available for service at the request of the ISO.

1.0 Requirements

The ISO shall develop and periodically review a Black Start restoration plan for the NYS Power System. The ISO may amend this restoration plan and determine Black Start requirements to account for changes in system configuration if the ISO determines that additional Black Start resources are needed. The ISO shall have the flexibility to seek Bids for new resources when it amends the current plan. The ISO shall establish procedures for acquiring Black Start Capability and testing selected Generators providing this service. The ISO shall make Black Start Capability payments only to those selected Suppliers that have appropriate Black Start equipment installed and available for service at the request of the ISO.

The full restoration of the NYS Power System will require some additional Black Start Generators, which are located in local Transmission Owner areas and which are not presently listed in the ISO restoration plan. Although the ISO plan will restore a major portion of the NYS Power System there are portions of the NYS Power System that will remain under Transmission Owner restoration control. Where the Transmission Owner's restoration plan requires additional Black Start service, the ISO will make payments for local area Black Start Capability directly to the Generators that provide that service, under the terms of this Rate Schedule. The LSEs in those local Transmission Owner areas will be additionally charged for that Black Start service by the ISO under the ISO OATT. Generators, which are obligated to provide Black Start service as a result of divestiture contract agreements, will not receive ISO payments for that service if they are already compensated for such service as part of those divestiture contracts.

2.0 Payment for Black Start Capability

By May 1st of each year, the following embedded cost information for Black Start equipment located at the Generators which were selected as essential for system restoration must be provided to the ISO based upon FERC Form No. 1 or equivalent data:

-Capital and fixed operation and maintenance costs associated with only those facilities within Generators that provide Black Start Capability; and

-Annual costs associated with training operators in system restoration.

Each Supplier will be paid on the basis of its costs filed with the ISO. The daily rate for Black Start Capability will be determined by dividing the Generator's annual cost by the number of days in the year from May 1st through April 30th of the following year.

The ISO (and Transmission Owner, when applicable) shall conduct Black Start Capability tests for providers of Black Start Capability. Any Generator that is awarded Black Start Capability payments and fails a Black Start Capability test shall forfeit all Black Start Capability payments made to that Generator since its last successful test. Payments to that Generator shall not resume until it successfully passes the Black Start Capability test.

ATTACHMENT A

FORM OF SERVICE AGREEMENT FOR NEW YORK ISO MARKET ADMINISTRATION AND CONTROL AREA SERVICES TARIFF

1.0 This Service Agreement dated as of ________________ is entered into by and between the New York Independent System Operator ("ISO") and _________________________ ("the Customer").

2.0 The Customer represents and warrants that it has met all applicable requirements set forth in the ISO Market Administration and Control Area Services Tariff (the "ISO Services Tariff") and has complied with all applicable ISO Procedures. The Customer has submitted a Completed Application pursuant to Article 9 of the ISO Services Tariff.

The ISO agrees to provide and the Customer agrees to pay for Market Services and Control Area Services in accordance with the provisions of the Tariff and to satisfy all obligations under the terms and conditions of the ISO Services Tariff, as may be amended from time-to-time, filed with the Federal Energy Regulatory Commission (the "Commission"). The ISO and the Customer also agree that this Service Agreement shall be subject to, and shall incorporate by reference, all of the terms and conditions of the ISO Services Tariff and ISO Procedures.

It is understood that, in accordance with the ISO Services Tariff, the ISO may amend the terms and conditions of this Service Agreement by notifying the Customer in writing and making the appropriate filing with the Commission.

3.0 The Customer represents and warrants that:

(a) The Customer is an entity duly organized, validly existing and/or otherwise qualified to do business under the laws of the State of New York, and is in good standing under its [insert organizational document] and the laws of the State of [insert state of organization];

(b) This Service Agreement, or any Transaction entered into pursuant to the Service Agreement, as applicable, has been duly authorized;

(c) The execution, delivery and performance of this Service Agreement will not materially conflict with, constitute a material breach of, or a material default under, any of the terms, conditions, or provisions of any law or order of any agency of government, the [insert organizational document] of the Customer, any contractual limitation, organizational limitation or outstanding trust indenture, deed of trust, mortgage, loan agreement, other evidence of indebtedness, or any other agreement or instrument to which the Customer is a party or by which it or any of its property is bound, or result in a material breach of, or a material default under, any of the foregoing; and

(d) This Service Agreement is the legal, valid, and binding obligation of the Customer enforceable in accordance with its terms, except as it may be rendered unenforceable by reason of bankruptcy or other similar laws affecting creditors' rights, or general principles of equity.

The Customer warrants and covenants that, during the term of the Service Agreement the Customer shall be in compliance with all federal, state and local laws, rules and regulations related to the Customer's performance under the agreement.

4.0 Service under this Service Agreement shall commence on the later of:

__________________, or such other date as it is permitted to become effective by the Commission. Service under this Service Agreement shall terminate on ______________________.

5.0 The ISO agrees to provide and the Customer agrees to take and pay for, or to supply to the ISO, Energy, Capacity and Ancillary Services in accordance with the provisions of the ISO Services Tariff and this Service Agreement.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below:

ISO:

____

____

____

Customer:

____

____

____

7.0 Cancellation Rights:

If the Commission or any regulatory agency having authority over this Service Agreement determines that any part of this Service Agreement must be changed, the ISO shall offer to the Customer an amended Service Agreement reflecting such changes. In the event that the Customer does not execute such an amendment within thirty (30) days, or longer if the Parties mutually agree to an extension, after the Commission's action, this Service Agreement and the amended Service Agreement shall be void.

8.0 Early Termination by the Customer:

The Customer may terminate service under this Service Agreement no earlier than ninety (90) days after providing the ISO with written notice of the Customer's intention to terminate; except that a Load Serving Entity must continue to take service under this Tariff as long as it continues to serve Load within the NYCA. In the event that tax-exempt financing of a Customer is jeopardized by its participation under this Service Agreement, the Customer may terminate this Service Agreement upon thirty (30) days prior written notice to the ISO. The Customer's provision of notice to terminate service under this Service Agreement shall not relieve the Customer of its obligation to pay any rates, charges, or fees due under this Service Agreement, and which are owed as of the date of termination.

9.0 The Customer hereby appoints the ISO as its agent for the limited purpose of effectively transacting on the Customer's behalf in accordance with the Customer's written instructions, listed herein and the terms of the ISO Services Tariff and ISO Procedures. The Customer agrees to pay all amounts due and chargeable to the Customer in accordance with the terms of the ISO Services Tariff and ISO Procedures.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

ISO:______________________________

By: ______________________________

Dated:_____________________________

Title: _____________________________

Customer:________________________

By:______________________________

Dated:____________________________

Title:____________________________

ATTACHMENT B

I. LBMP CALCULATION METHOD

The Locational Based Marginal Prices ("LBMPs") for Generators and Loads will be based on the system marginal costs produced by either the Security Constrained Dispatch ("SCD") program for Real-Time Market prices, or the Security Constrained Unit Commitment ("SCUC") program for Day-Ahead Market prices. These will be utilized in an *ex post* computation to produce LBMP bus prices using the following equations.

The LBMP at bus i can be written as :

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

Where:

γ_i = LBMP at bus i in \$/MWh

λ^R = the system marginal price at the Reference Bus

γ_i^L = Marginal Losses Component of the LBMP at bus i which is the marginal cost of losses at bus i relative to the Reference Bus

γ_i^C = Congestion Component of the LBMP at bus i which is the marginal cost of Congestion at bus i relative to the Reference Bus

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

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

Where:

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

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

Where:

L = system losses; and

P_i = generation injection at bus i

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

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

Where:

K = the set of thermal or Interface Constraints;

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

μ_k = the reduction in system cost that results from an incremental relaxation of Constraint k expressed in \$/MWh.

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

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

The SCD program execution in a given interval may terminate without observing the limits on all Constraints, usually due to Generator ramp rate limitations on the dispatch. Under these conditions, rules have been developed which the ISO will use to set Generator output levels and to calculate LBMPs. These rules state that the LBMPs are to be calculated from the output of the SCD execution in which Constraints were violated. Prices calculated in this manner closely reflect the marginal cost of Energy on the system. However, the Generator output levels will be set by a second SCD execution in which Generator ramp rate constraints are relaxed. This execution of SCD usually eliminates the Constraint violations and will provide the dispatcher with information to correct the situation. Often Generators will be able to operate at the levels set in the second SCD execution, since they frequently can change their output levels at rates exceeding those included in the Bid data provided to the ISO. Failure to achieve the output levels determined in the second SCD execution will not cause the Generator's performance ratings in the Performance Tracking System to be adversely affected.

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

Zonal LBMP Calculation Method

The computation described above is at the bus level. This will be suitable for Generator buses because adequate metering is available, or will be provided, to measure real-time injections. An eleven (11) zone model will be used for the LBMP billing related to Loads. The LBMP for a zone will be a Load weighted average of the Load bus LBMPs in the zone. The Load weights which will sum to unity will be predetermined by the ISO. Each component of the LBMP for a zone will be calculated as a Load weighted average of the Load bus LBMP components in the zone. The LBMP for a zone *j* can be written as:

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

where: γ_j^Z = LBMP for zone j,

$$\gamma_j^{L,Z} = \sum_{i=1}^{n} W_i \gamma_i^L$$

is the Marginal Losses Component of the LBMP for zone j;

$\gamma_j^{C,Z} = \sum W_i \gamma_i^C$ is the Congestion Component of the LBMP for zone j;

n = number of load buses in zone *j* for which LBMPs are calculated; and

W_i = load weighting factor for bus *i*.

Until the ISO's software can compute LBMPs at Load buses, the zonal LBMPs will be a weighted average of the Generator bus LBMPs in the zone. The weightings will be pre-determined by the ISO.

LBMP Prices for External Locations

External Generators and Loads can bid into the LBMP Market or participate in Bilateral Transactions. External Generators may arrange Bilateral Transactions with Internal or External Loads and External Loads may arrange Bilateral Transactions with Internal Generators.

The Generator and Load locations for which LBMPs will be calculated will initially be limited to a pre-defined set of buses External to the NYCA. LBMPs will be calculated for each bus within this limited set. The three components of LBMP will be calculated from the results of SCD and posted in the Day-Ahead and Real-Time Markets as described above, except that the Marginal Losses Component of LBMP will be calculated differently for Internal locations. The Marginal Losses Component of the LBMP at each bus, as described above, includes the difference between the marginal cost of losses at that bus and the Reference Bus. If this formulation were employed for an External bus, then the Marginal Losses Component would include the difference in the cost of Marginal Losses for a section of the transmission system External to the NYCA. Since the ISO will not charge for losses incurred Externally, the formulation will exclude these loss effects. To exclude these External loss effects, the Marginal Losses Component will be calculated from points on the boundary of the NYCA to the Reference Bus.

The Marginal Losses Component of the LBMP at the External bus will be a weighted average of the Marginal Losses Components of the LBMPs at the Interconnection Points. To derive the Marginal Losses Component of the LBMP at an External location, a Transaction will be assumed to be scheduled from the External bus to the Reference Bus. The Shift Factors for this Transaction on the tie lines into these Interconnection buses, which measure the per-unit effect of flows over each of those tie lines that results from the hypothetical transaction, will provide the weights for this calculation. Since all the power from this assumed Transaction crosses the NYCA boundary, the sum of these weights is unity.

The sum of the products of these Shift Factors and the Marginal Losses Component of the LBMP at each of these Interconnection buses yields the Marginal Losses Component of the LBMP that will be used for the External bus. Therefore, the Marginal Losses Component of the LBMP at an External bus E is calculated using the equation:

$$\gamma_E^L = \sum_{b \in I} F_{Eb}(DF_b - 1)\,\lambda^R$$

where:

γ_E^L = Marginal Losses Component of the LBMP at an External bus E;

F_{Eb} = Shift Factor for the tie line going through bus b, computed for a hypothetical Bilateral Transaction from bus E to the Reference Bus;

$(DF_b - 1)\lambda^R$ = Marginal Losses Component of the LBMP at bus b; and

I = The set of Interconnection buses between the NYCA and adjacent Control Areas.

II. ACCOUNTING FOR TRANSMISSION LOSSES

1.0 Charges

Subject to Attachment K to the ISO OATT, 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.

1.1 Loss Matrix

The ISO's Security Constrained Dispatch ("SCD") program will use a loss matrix (referred to as a B matrix) and penalty factors to estimate and model losses in performing generation dispatch and billing functions for losses.

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 Parts II, III and IV of the ISO OATT) 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).

2.0 Computation of Residual Loss Payments

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.

2.1.1 Marginal Losses Component Day-Ahead

The ISO shall utilize the Marginal Losses Component computed by the ISO's Security Constrained Unit Commitment ("SCUC") program for computing the marginal contributions of each Transaction in the Day-Ahead Market.

2.1.2 Marginal Losses Component Real-Time

The ISO shall utilize the Marginal Losses Component computed by the ISO's Security Constrained Dispatch ("SCD") 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 a SCD interval basis and aggregated to an hourly total.

2.2 Payments and Charges

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

Day-Ahead Payments and Charges

As part of the LBMP paid to all Suppliers scheduled Day-Ahead to provide Energy to the LBMP Market, the ISO shall pay each such Supplier the product of: (a) the injection scheduled Day-Ahead from each of that Supplier's Generators in each hour, in MWh; and (b) the Marginal Losses Component of the Day-Ahead LBMP at each of those Generators' buses, in $/MWh.

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 injected and 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 if the 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.

Real-Time Payments and Charges

As part of the LBMP paid to all Suppliers providing Energy to the LBMP Market in the real-time dispatch, the ISO shall pay each such Supplier the product of: (a) the amount of Energy actually injected by each of that Supplier's Generators in each hour (to the extent that actual injections do not exceed the AGC or SCD Base Points Signals sent to that Supplier for those Generators), minus the amount of Energy each of those Generators was scheduled Day-Ahead to inject in that hour, in MWh; and (b) the loss component of the Real-Time LBMP at each of those Generator's buses, in $/MWh.

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 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) the amount of Energy scheduled (as of the BME) to be injected and withdrawn by that Transmission Customer in each hour, minus the amount of Energy scheduled Day-Ahead to be injected and 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.

As part of the LBMP paid to all Suppliers generating an amount of Energy that differs from the amount of Energy those Suppliers were scheduled (as of the BME) to generate in an hour in association with Bilateral Transactions, the ISO shall pay each such Supplier the product of: (a) the amount of Energy actually injected by each of that Supplier's Generators in each hour (to the extent that actual injections do not exceed the AGC or SCD Base Points Signals sent to that Supplier for those Generators), minus the amount of Energy each of those Generators was scheduled (as of the BME) to inject in that hour in association with Bilateral Transactions, in MWh; and (b) the Marginal Losses Component of the Real-Time LBMP at each of those Generators' buses, in $/Mwh.

As part of the LBMP charged to all LSEs consuming an amount of Energy that deviates from the amount of Energy those LSEs were scheduled (as of the BME) to consume in an hour in association with Bilateral Transactions, 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 (as of the BME) in that Load Zone by that LSE for that hour in association with Bilateral Transactions, in MWh; and (b) the Marginal Losses Component of the Real-Time LBMP in that Load Zone, in $/MWh.

III. BILATERAL TRANSACTION BIDDING, SCHEDULING AND CURTAILMENT

1.0 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:

(1) Point of Injection location. For Transactions with Internal sources, the Point of Injection is the LBMP bus; for Transactions with External sources, the Point of Injection is the Proxy Generator Bus; however, based upon 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.

(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;

(3) Hourly MW schedules;

(4) Whether Firm or non-Firm Transmission Service is requested;

(5) NERC Transaction Priorities for Bilateral Transactions involving External Generators, Exports, and Wheels Through;

(6) An optional Decremental Bid for the Bilateral Transaction up to the MW level of the desired schedule (if the Transmission Customer does not submit a Decremental Bid, the ISO shall assign one in accordance with Section 2.3 below);

(7) For an Internal Generator, whether the Generator is On-Dispatch or Off-Dispatch;

(8) The amount (in MW) of any additional Energy to be provided by the Transmission Customer to cover Marginal Losses associated with the Bilateral Transaction and the location of the Generator supplying that Energy;

(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

(10) Other data required by the ISO.

2.0 Bilateral Transaction Scheduling

2.1 ISO's General Responsibilities

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 the BME to establish schedules for each hour of dispatch in that day.

If required by SCD, the ISO shall Curtail Transmission Service during dispatch as described in this Attachment.

2.2 Use of Decremental Bids to Dispatch Internal Generators

When dispatching Generators to match changing conditions, the ISO shall treat Decremental Bids and Incremental 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 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 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.

2.3 Default Decremental Bids

If an optional Decremental Bid is not provided, the ISO shall assign and post a default Decremental Bid. The default Decremental Bid will be based upon a large, negative value to be applied between 0 MW and the total amount (in MW) of the Transmission Service. If a Transmission Customer who is using Grandfathered Rights to schedule Transmission Service in the Day-Ahead Market does not provide a Decremental Bid in association with that Transmission Service the ISO shall assign a default Decremental Bid equal to the lowest Decremental Bid that can be entered by a unit bidding into SCUC (as constrained by limitations of the bidding software), minus an additional $100/MWh.

2.4 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 BME 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 customers 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 BME 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 SCD intervals that elapse before the implementation of Reduction).

2.5 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 and Decremental 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.

2.6 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, an Export, 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 based on the Day-Ahead schedule of the Transaction and, in addition, the Generator 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 Transaction was scheduled following the Day-Ahead Market, or the schedule for the Transaction was revised following the Day-Ahead Market, then the ISO will supply the Load or Transmission Customer in an Export with Energy from the Real-Time LBMP Market 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) if 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 scheduled in the BME to be transmitted in association with that Transaction minus the amount of Energy scheduled Day-Ahead to be transmitted in association with that Transaction. In addition, to the extent that it has not purchased sufficient replacement Energy in the Day-Ahead Market, the Generator 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. (In cases where Export Transactions are Curtailed by the actions of operators of other Control Areas, the amount of Energy scheduled Day-Ahead to be consumed in association with such Transactions shall be revised to reflect the effects of any such Curtailments.)

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 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 BME 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 Decremental Bids; and (3) prorate Curtailment if Decremental Bids within a priority category are equal.

(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 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 Decremental Bids, and (2) prorating Curtailment if Decremental Bids are equal;

(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 be respond to SCD 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.

2.7 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 BME 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 BME. 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 resulting from the actions of operators of these Control Areas, but the amount of Transmission Service scheduled for those Transactions will remain unchanged. However, any Curtailment or Reductions of schedules for Import or Export Transactions directed by the ISO will cause both the DNI and the scheduled amount of Transmission Service to change.

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 BME, which, in turn, will determine the Transmission Service scheduled in the BME 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.

IV. SALE OF TRANSMISSION CONGESTION CONTRACTS (“TCCs”)

1.0 Overview of the Sales of TCCs

TCCs will be made available through both (i) the Centralized TCC Auction (“Auction”), which will be conducted under the direction of the ISO; and (ii) Direct Sales by the Transmission Owner, which will be non-discriminatory, auditable sales conducted solely on the OASIS in compliance with the applicable requirements and restrictions set forth in Order No. 889 et. seq.

Before each Auction, the ISO shall ensure that all Grandfathered Rights and Grandfathered TCCs correspond to a simultaneously feasible Power Flow. Should infeasibility occur, the TCC Reservations shown in Table 1 of this Attachment will be reduced until feasibility is assured, as described in Section 3.0 below.

After the establishment of a feasible set of Grandfathered Rights and Grandfathered TCCs, there will be an initial allocation of TCCs associated with any transmission capability that remains after Grandfathered Rights and Grandfathered TCCs have been taken into account. These Residual TCCs will be allocated to the Transmission Owners. Transmission Owners will be required to either sell these initial Residual TCCs through a Direct Sale on the OASIS prior to each Auction, or to sell them through each Auction. Each Transmission Owner may retain its Grandfathered TCCs except as noted in the next paragraph. If it sells those TCCs, it shall do so either through Direct Sales or through Auctions.

Upon implementation of the ISO, Transmission Owners with Existing Transmission Capacity for Native Load ("ETCNL") will release that capacity for sale in the Auction.

2.0 General Description of the Auction Process

First, the ISO will conduct a Transitional Auction, which will make TCCs available to Market Participants for the period between the time at which the ISO begins operation and the time at which the ISO has completed the development of the software that will be necessary in order to perform a multiple-round auction. The ISO shall then conduct an Initial Auction, in which long-term TCCs will be available. This auction will consist of multiple rounds. The proportion of system transfer capability that will be set aside to support TCCs of varying durations will be determined before the Initial Auction is conducted. Then later, upon the completion of more sophisticated Auction software, the ISO will perform an End-State Auction, which will permit the bids submitted by Auction participants to determine the lengths of the TCCs sold in the Auction. Each of these types of Auctions is described in additional detail later in this Attachment.

The Initial Auction will consist of a series of sub-auctions. These sub-auctions and the End-State Auction will be conducted in two stages, with each stage including several rounds. The transmission capacity that has been offered for sale in Stage 1 will be auctioned in not less than four (4) rounds, unless the Transmission Owners unanimously consent to fewer rounds. A portion of that capacity will be auctioned in each of those rounds. In Stage 1, the TCCs available for sale in the Auction will include the Residual TCCs and ETCNL initially allocated to the Transmission Owners (but not sold through a Direct Sale) and any other TCCs offered for sale by a Primary Holder. In Stage 2, holders of TCCs may indicate whether they wish to sell those TCCs into a given round before that round begins. All of the TCCs that have been offered for sale in each round of Stage 2 will be auctioned in that round. Each Primary Owner, purchaser of a TCC in a previous round of the Auction, or purchaser of a TCC in a Direct Sale (if it meets the ISO's creditworthiness standards) may offer its TCCs for sale in any round of Stage 2. No one will be required to offer TCCs for sale in Stage 2.

The ISO shall hire an auctioneer to conduct the Auctions (with the exception of the Transitional Auction, for which the ISO may elect to hire an auctioneer). The auctioneer will run a Power Flow to determine the feasibility of TCCs to be auctioned. The Power Flow model will treat all Grandfathered Rights and all Grandfathered TCCs (that have not been offered for sale in the Auction) and all Residual TCCs sold through a Direct Sale (that have not been offered for sale in the Auction) as fixed injections and withdrawals corresponding to the Points of Injection and Withdrawal for each of those Grandfathered Rights or Grandfathered TCCs, or Residual TCCs. As each ETA terminates, the Grandfathered Rights or TCCs associated with the ETA shall be released for sale into the Auction. The revenues associated with the Auction of these TCCs shall be allocated among the Transmission Owners according to the Interface MW-Mile Methodology, as described in Attachment N to the ISO OATT.

In the Auction, bidders will place Bids specifying the maximum amount they are willing to pay for the TCCs they wish to purchase. The objective of the Auction will be to maximize the value of the TCCs awarded to the bidders, as valued by their Bids, subject to the Constraint that the set of all outstanding TCCs and Grandfathered Rights must correspond to a simultaneously feasible security-constrained Power Flow.

The Auction will determine prices for feasible TCCs. All bidders awarded TCCs in a round of the Auction will pay the Market Clearing Price in that round for those TCCs. Similarly, all TCC holders selling TCCs through the Auction will be paid the Market Clearing Price in that round for those TCCs.

Following the first Initial Auction, the ISO will conduct Reconfiguration Auctions on a monthly basis. At the discretion of the ISO Reconfiguration Auctions may be conducted prior to the Initial Auction. Holders of TCCs that are valid for the next month will be permitted to offer those TCCs for sale in the Reconfiguration Auction (as described in Section 8.6) for that month. Winning bidders in a Reconfiguration Auction will be awarded TCCs that will be valid for the next month.

3.0 Description of the Reduction Process

In some cases, the total set of Grandfathered TCCs (including ETCNL and TCCs allocated to participants in existing transmission contracts) may not correspond to a simultaneously feasible Power Flow. In such cases, the TCCs Subject to Reduction, as listed in Table 1 of this Attachment (henceforth "Table 1 TCCs"), will be reduced in order to make the total set of Grandfathered TCCs correspond to a simultaneously feasible Power Flow.

This reduction procedure will use the same optimization model that will be used in the TCC Auction to determine the amount by which Table 1 TCCs will be reduced. Initially, each Grandfathered TCC that is not included in Table 1 will be represented in the Auction model by a fixed injection of 1 MW at that TCC's injection location, and a fixed withdrawal of 1 MW at that TCC's withdrawal location. Bids for each Table 1 TCC will consist of a line which intersects the y-axis at $1 (or any other value selected by the ISO, so long as that value is constant for each bid curve for one of these TCCs) and which intersects the x-axis at 1 MW. An example of the bid curve B_j for a representative Table 1 TCC is illustrated in the diagram below.

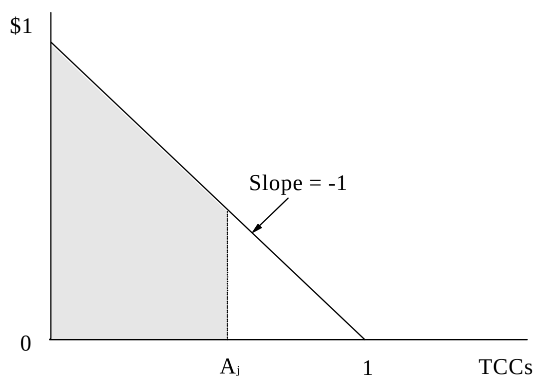
The TCC Auction software will determine the proportion of each Table 1 TCC that will remain after reduction, which is designated as A_j in the diagram. The objective function that the

TCC Auction software will use to determine these coefficients A_j will be to maximize

$$\sum_{j \in N} \int_0^{A_j} B_j$$

where N is the set of Table 1 TCCs, and all other variables are as defined above, subject to the constraint that injections and withdrawals corresponding to all Grandfathered TCCs (including the remaining Table 1 TCCs), must be simultaneously feasible. As a result, the objective function will

Bid Curve B_j for TCC j



maximize the area under the bid curve for each Table 1 TCC that remains after reduction, summed over all Table 1 TCCs, subject to the simultaneous feasibility constraint. This area for one Table 1 TCC is illustrated in the diagram.

4.0 Transition from OATT Service

The timing and transitional arrangements for the first Auction are as follows:
The first Auction will begin on the First Effective Date, which is twwenty-eight (28) days before the first day of operation of the LBMP Market (which shall occur on the Second Effective Date). It will end two weeks prior to the Second Effective Date.

Two (2) weeks before the first Auction (six (6) weeks prior to the first day of operation of the LBMP Market), customers will no longer be permitted to enter into new long-term agreements under the Transmission Owners' current Open Access Transmission Tariffs ("OATTs") that would be grandfathered after the first day of operation of the LBMP Market. It is necessary for the Transmission Owners to cease offering new long-term OATT service before the First Effective Date in order to be able to determine the transmission capacity that can be sold in the first Auction.

Until the Second Effective Date, Transmission Customers will continue to be able to enter into new short-term agreements for monthly, weekly, or daily service under the Transmission Owners' current OATTs, terminating no later than the First Effective Date.

The Transmission Owners will not have the opportunity to sell their Residual TCCs through a Direct Sale, as described in this Attachment, before the first Auction.

Two (2) weeks before the first Auction, customers with Existing Transmission Agreements (including grandfathered OATT service) will be required to indicate whether they will opt to elect to convert their existing transmission rights to TCCs or to take Grandfathered Rights, in accordance with Attachment K to the ISO OATT.

5.0 Calculation of Residual Transmission Capacity to Establish Residual TCCs

Before the first Auction, the ISO shall calculate the Residual Transmission Capacity across each transmission Interface in both the Summer and Winter Capability Periods from the Operating Study Power Flow dispatch. The ISO shall determine the MW flow across each Interface in this Operating Study Power Flow. The ISO shall determine the Residual Transmission Capacity across each Interface in each Capability Period by subtracting the effects of injections and withdrawals corresponding to all Grandfathered TCCs and Grandfathered Rights on the MW flow across each Interface (which will be determined using a Shift Factor Analysis) from the MW flow determined in the Operating Study Power Flow.

The ISO shall then allocate the Residual Transmission Capacity across Interfaces to individual Transmission Owners in the form of Residual TCCs in accordance with the Interface MW-Mile Methodology. This allocation shall conform to a feasible set of TCCs. The ISO's allocation of Residual TCCs to Transmission Owners shall remain the same for at least the duration of the LBMP Transition Period. At the conclusion of the LBMP Transition Period, the Transmission Owners will review this methodology and shall have the sole discretion to modify by unanimous vote, the procedure to be used to allocate Residual Transmission Capacity across Interfaces in the form of Residual TCCs, and to determine the duration of all such Residual TCCs allocated.

Residual TCCs for each Interface will constitute point-to-point TCCs, each from a Point of Injection in one Load Zone to a Point of Withdrawal in another Load Zone. The ISO shall calculate the number of Residual TCCs that each Transmission Owner will receive from each Point of Injection to each Point of Withdrawal by calculating the product of: (a) the number of Residual TCCs to be allocated to each Transmission Owner across each Interface; (b) the ratio of Load served at that TCC's Point of Injection to total Load in the Load Zone containing that Point of Injection; and (c) the ratio of Load served at that TCC's Point of Withdrawal to total Load in the Load Zone containing that Point of Withdrawal. When estimating the amount of Load served at each bus (Point of Injection or Point of Withdrawal), the ISO shall use the same bus Loads used for calculating Zonal LBMPs.

6.0 Secondary Market for TCCs

After the conclusion of each Auction, all holders may sell those TCCs in the Secondary Markets. However, the ISO shall make all Settlements with Primary Holders.

7.0 Sale of TCCs by Transmission Owners directly over the OASIS ("Direct Sale")

Transmission Owners may sell their Residual TCCs and Grandfathered TCCs directly to buyers through a Direct Sale, except that TCCs will not be sold through Direct Sales before the Transitional Auction. Sellers and potential buyers shall communicate all offers to sell and buy TCCs, through a Direct Sale, solely over the ISO's OASIS.

Buyers in a Direct Sale that elect to become Primary Holders must meet the eligibility criteria in Section 11.0 of the ISO OATT. In addition, each buyer that elects to become a Primary Holder shall submit information to the ISO regarding the buyer's creditworthiness, as the ISO may require, along with a statement signed by the buyer, representing that the buyer is financially able and willing to pay for the TCCs it proposes to purchase as well as all other obligations associated with the purchase of such TCCs, including without limitation, Congestion Rents. The aggregate value of the buyer's offers to purchase TCCs (either in Direct Sales or in the Auction) and a reasonable estimate of the buyer's obligations associated with the purchase of such TCCs shall not exceed the buyer's ability to pay, as determined by the ISO (based upon an analysis of the buyer's creditworthiness).

Where a buyer electing to become a Primary Holder fails to meet the eligibility criteria or the above financial criteria (as determined by the ISO), or fails to provide information required by the ISO, the seller of the TCCs in the Direct Sale shall be the Primary Holder with respect to those TCCs. The ISO shall make all Settlements with Primary Holders.

During the Direct Sale process, the Transmission Owner shall have the sole discretion to accept or reject an offer to purchase TCCs. Each Transmission Owner shall develop and apply a non-discriminatory method for choosing the winning offers consistent with the Commission's Order No. 889, et seq., and may establish eligibility requirements that shall be no more stringent than those set forth in Section 11.0 of the ISO OATT. The Transmission Owner shall post information regarding the results of the Direct Sale on the OASIS, promptly after the Direct Sale is completed. The information shall include: (i) the amount of TCCs sold (in MW); (ii) the Point of Injection and Point of Withdrawal for each TCC sold; and (iii) the price paid for each TCC.

Primary Owners of Residual TCCs shall inform the ISO of all sales of those TCCs, including the identity of the buyers. Transmission Owners may offer to sell Residual TCCs for a period not extending beyond the end of the LBMP Transition Period, and Grandfathered TCCs for periods not extending beyond the termination date of those TCCs; however, these TCCs shall not be valid (i.e., the Congestion Rent obligations of the holders of those TCCs shall not commence) until TCCs sold in the first Initial Auction become valid. Payment for TCCs purchased in a Direct Sale shall be in accordance with the terms and conditions of the agreement between the buyer and seller.

8.0 Auctions for TCCs

8.1 Transmission Capacity Sold in Centralized Auctions for TCCs

In the Auction the following transmission capacity shall be available for purchase in the form of TCCs: (1) all of the transmission capacity associated with ETCNL that the Transmission Owners do not sell through a Direct Sale in advance of the Auction; (2) all of the transmission capacity associated with Residual TCCs that the Transmission Owners do not sell through a Direct Sale in advance of the Auction; or (3) any other transmission capacity in excess of that claimed by ETAs and Residual TCCs.

Direct sales of TCCs by Transmission Owners will not be permitted prior to the Transitional Auction. TCCs made available in this Auction shall be subject to the provisions of each Transmission Owner's retail access program.

8.2 Transitional Auction

Prior to the first day of operation of the LBMP Market, TCCs will be sold that will be valid from the first day of operation of the LBMP Market to the first day of the Summer 2000 Capability Period.

8.3 Phases of Long-Term TCC Auction

The ISO will make long-term fixed-price transmission service available through the sale of long-term TCCs in an Auction which will be accomplished in two phases.

Phase 1: "Initial Auction" for Long-Term TCCs - The TCCs purchased in this Auction shall be valid on the first day of the Summer 2000 Capability Period. These TCCs will have varying durations. TCCs available for each of these durations will be sold in a separate "sub-auction."

Phase 2: "End-State Auction" for Long-Term TCCs - In the end state, TCCs of different durations will be sold in a single Auction.

8.4 Transitional Auction

The Transitional Auction will be accomplished through one round of bidding. It will not have two stages or multiple rounds. Any Primary Owner may offer its TCCs for sale in this Auction.

8.5 Phase 1: Initial Auction for Long-Term TCCs

TCCs with durations of six (6) months and 1 year shall be available in the Initial Auction. TCCs with durations of two (2) years, three (3) years, four (4) years or five (5) years may also be available in this Auction.

The percentage of the transmission capacity that is sold in the Auction as TCCs of each of these different durations will be determined by the ISO, subject to certain limits. In the Auction held in the spring of 2000, the ISO must sell no less than 65% of the transmission capacity sold in the Auction as TCCs with either a 6 month or 1 year duration. Subject to this constraint, the final decision concerning the percentage of the transmission capacity that will be sold in the Auction as TCCs of different durations will be made by the ISO. The ISO will conduct a polling process to assess the market demand for TCCs with different durations, which it will take into consideration when making this determination. The ISO may elect not to sell any TCCs with one or more of the above durations. However, all transmission capacity not associated with ETAs or outstanding TCCs must be available to support TCCs of some duration sold in the Auction.

The Initial Auction will consist of a series of sub-auctions, which will be conducted consecutively in the spring of 2000. In each sub-auction, TCCs of a single duration will be available (e.g., only TCCs with a five-year duration might be available in one sub-auction). Sub-auctions will be conducted in decreasing order of the length of the period for which TCCs sold in the sub-auction are valid. Therefore, if the ISO were to determine that five (5) years would be the maximum length of TCCs available in the Initial Auction, then the sub-auction for TCCs with a duration of five years would be held first. All TCCs sold in the 5-year TCC sub-auction (other than those offered for sale in the next sub-auction, as described below) would then be modeled as fixed injections and withdrawals in the next sub-auction, in which TCCs of the next longest duration, as determined by the ISO (e.g., four (4) years), would be available for purchase. Following that sub-auction, TCCs sold in either of the first two sub-auctions (other than those offered for sale in the next sub-auction) would then be modeled as fixed injections and withdrawals in the third sub-auction (e.g., a sub-auction for TCCs with a duration of three years), etc.

TCCs purchased in any sub-auction may be resold in a subsequent sub-auction. For example, the purchaser of a 5-year TCC purchased in the five (5) year sub-auction may release a 4-year TCC with the same injection and withdrawal points for sale in the 4-year sub-auction. Similarly, that purchaser could instead release a corresponding 3-year TCC for sale in the 3-year sub-auction. Any TCC that was outstanding before the Initial Auction may be released for sale in any sub-auction.

Each sub-auction shall consist of two stages, and each of the stages of which shall consist of at least four rounds. The ISO shall have the authority to determine the percentage of the available transmission capacity that will be sold in each round of each sub-auction. The ISO shall not announce these percentages before the sub-auctions. The ISO shall also determine the maximum duration of TCCs sold in the Initial Auction, subject to the limitations above, and whether the TCCs sold in an Initial Auction shall be separately available for purchase as peak and off-peak TCCs. (For purposes of this Attachment, the peak period will include the hours from 7 a.m. to 11 p.m. Prevailing Eastern Time Monday through Friday. The remaining hours in each week will be included in the off-peak period.)

Following the Initial Auction the ISO will conduct an Auction in the fall of 2000 in which TCCs for the Winter 2000-2001 Capability Period will be available for purchase. In that Auction, all TCCs that were awarded in the Initial Auction will be modeled as fixed injections and withdrawals, with the exception of (i) TCCs with a duration of six months that were sold in the Initial Auction and (ii) any other TCCs sold in that Auction whose holders elect to release them for sale in the Winter 2000-2001 Auction. Any holder of an outstanding TCC may release it for sale in this Auction.

If necessary (e.g., due to delays in the development in the software required to implement the End-State Auction), the Initial Auction will be repeated in subsequent years, e.g., in the spring of 2001. In that event, the rules described above to govern the operation of an Initial Auction shall be applied to any repeated Initial Auction, with the exception that the minimum proportion of transmission capacity required to be aside to support TCCs with a duration of six months or one year will not apply. All available transmission capacity will be sold in these Auctions, including transmission capacity that would have been required to support Residual TCCs that the Transmission Owners do not sell directly in advance of the Auction, any other transmission capacity in excess of that claimed by grandfathered transmission agreements, Residual TCCs and long-term TCCs sold in previous Auctions whose holders offer those TCCs into the Auction.

8.5 Phase 2: End-State Auction for Long-Term TCCs

The End-State Auction will be held annually. The date for the first End-State Auction shall be determined by the ISO. The period during which each TCC sold in an End-State Auction is valid shall begin on the beginning date of a Capability Period, and shall conclude on the ending date of a Capability Period.

The ISO will determine the maximum duration and minimum duration of the TCCs available in the End-State Auctions. The ISO shall have the authority to determine the percentage of the available transmission capacity that will be sold in each round of the Auction. The ISO shall not announce these percentages before the Auction. The ISO shall also determine the periods for which TCCs will be sold in End-State Auctions (e.g., TCCs valid during peak and off-peak periods, or TCCs valid during Winter and Summer Capability Periods). The ISO may elect to vary the duration or the periods for which TCCs will be available from one End-State Auction to the next End-State Auction.

The End-State Auction will not include separate sub-auctions for TCCs of different durations. Instead, TCCs of each permitted duration will be allocated as the result of the operation of a single Auction. If a Market Participant wishes to purchase a TCC beginning in the Summer Capability Period of 2003, and ending in the Winter Capability Period of 2004-2005, it would submit a single Bid for this TCC. If that Bid is a winning Bid, the bidder would be awarded a TCC valid for the entire two year-long period; if the Bid is a losing Bid, the bidder would not receive the TCC for any portion of this period. The ISO will not specify in advance the portion of system transfer capability that will be used to create TCCs of differing durations. Rather, the durations of TCCs awarded will be determined as part of the Auction, and will depend on the Bids submitted by participants in the Auction.

In a given round of the End-State Auction, the Market Clearing Price determined for a TCC that is valid for multiple Capability Periods will equal the sum of the Market Clearing Prices for shorter-term TCCs with the same injection and withdrawal locations, which in the aggregate cover the same period for which the longer-term TCC is valid. (For example, the price of a TCC that is valid from May 2001 through April 2003 would equal the sum of the prices in that round for (1) TCCs valid from May 2001 through Winter 2002 and (2) TCCs valid from May 2002 through April 2003.

The End-State Auction will include two stages, with each stage including multiple rounds of bidding, as described in this Attachment.

Transmission capacity that can be used to support TCCs sold in End-State Auctions shall include all capacity except that necessary to support the following: Residual TCCs that the Transmission Owners sell directly in advance of the Auction; any TCCs previously allocated (either in an Auction or through other means) that have not been offered for sale in this

Auction; and transmission capacity needed to support Grandfathered Rights.

The End-State Auction will allow reconfiguration of the TCCs sold in the previous Auctions. An entity holding a five-year TCC, for example, may release a TCC for some or all of the period for which that TCC is valid for sale in the End-State Auction.

If necessary, the ISO may elect to conduct a semi-annual Auction to sell six-month TCCs between annual End-State Auctions. The transmission capacity that can be used to support TCCs purchased in this Auction shall include the portion of the transmission capacity sold in the previous End-State Auction as six-month TCCs, as well as any other outstanding TCC whose Primary Holder elects to release it for sale in this Auction.

8.6 Reconfiguration Auctions

A Reconfiguration Auction is an Auction in which monthly TCCs may be offered and purchased. This will allow Market Participants to purchase and sell short-term TCCs. This Auction will also capture short-term changes in transmission capacity. Following each Initial or End-State Auction, the ISO will conduct Reconfiguration Auctions. The ISO may conduct a Reconfiguration Auction prior to Initial Auction. The Reconfiguration Auctions will be held monthly, beginning one month after the first Initial Auction of long-term TCCs, and TCCs purchased in Reconfiguration Auctions will be valid for the month following the Reconfiguration Auction. It will consist of a single round. Any Primary Holder of a TCC, including a purchaser of a TCC in an Auction that has not sold that TCC, may offer that TCC for sale in a Reconfiguration Auction. The transmission capacity used to support these TCCs, as well as any other transmission capacity not required to support already-outstanding TCCs, will be available to support TCCs purchased in the Reconfiguration Auction.

9.0 Procedures for Sales of TCCs in Each Auction

9.1 Auction Structure

Eligibility to Bid in Stage 1 and Stage 2 - TCCs may be offered for sale in each stage of the Auction. Primary Owners (who have not sold their TCCs in a Direct Sale), purchasers of TCCs in Direct Sales (who qualify as Primary Holders), and purchasers of TCCs in previous Auctions (who have not subsequently sold their TCCs) may offer TCCs for sale in Stage 1. If they do so, they must specify all of the TCCs they wish to offer in Stage 1 before Stage 1 begins. The following holders of TCCs may offer to sell TCCs in each round of Stage 2: (i) Primary Owners who did not sell those TCCs in a Direct Sale or in a previous round of the Auction (in either Stage 1 or Stage 2); (ii) purchasers of TCCs in previous rounds of that Auction or in previous Auctions who have not subsequently sold those TCCs through an Auction; and (iii) purchasers of TCCs through a Direct Sale who qualify to become Primary Holders and have not already sold those TCCs through an Auction or through a Direct Sale.

Bid Requirements - Bidders shall submit Bids into the Auction in accordance with this Attachment. Bidders shall submit Bids such that the sum of the value of its Bids (excluding Bids for TCCs already held by that bidder) shall not exceed that bidder's ability to pay for TCCs.

Bidding Rounds - Bidders shall be awarded TCCs in each round of the Auction and shall be charged the Market Clearing Price for that round, as defined in this Attachment, for all TCCs they purchase. For purposes of determining payments to Primary Holders who release TCCs into the Auction, each Primary Holder that offers TCCs for sale in Stage 1 of the Auction shall be deemed to have offered a portion of those TCCs for sale in each round of Stage 1 based on the scaling factors defined by the ISO for each round of the Auction (as further defined below). Prior to each Auction, the ISO shall determine the percentage of TCCs to be offered for sale in each round of Stage 1 of the Auction, such that all of the TCCs offered for sale in Stage 1 shall be offered by the last round of Stage 1. The percentages may be different in each round. The "scaling factor" for each round in Stage 1 shall equal the percentage of TCCs to be sold in Stage 1 that have not already been sold in a previous round of Stage 1, divided by the percentage of TCCs to be sold in that round of Stage 1. TCCs that may be sold in each round shall be determined by dividing the TCCs offered for sale in Stage 1 by the scaling factor applicable to that round (See examples in Section 9.9 below.)

Stage 2 of the Auction shall terminate: (i) if no Primary Owner of a Grandfathered or Residual TCC or purchaser of TCCs in an earlier round of the Auction offers to sell any TCCs in a round; (ii) if no TCCs are purchased or sold in two (2) consecutive rounds; or (iii) upon the satisfaction of other criteria defined by the ISO.

Primary Holders - The ISO shall make all Congestion Rent Settlements with Primary Holders.

Transitional and Reconfiguration Auctions - All rules stated in this Section for Stage 1 of an Initial or an End-State Auction shall also apply to Transitional and Reconfiguration Auctions. The scaling factor for the single round of a Transitional and Reconfiguration Auction shall be one, since all transfer capability other than that needed to support already-outstanding TCCs will be available to support TCCs sold in the Auction.

9.2 Responsibilities of the ISO

The ISO shall establish the Auction rules and procedures consistent with the ISO OATT. The ISO shall hire an auctioneer to conduct the commercial aspects of the Auction (except that the ISO shall not be required to hire an auctioneer for the Transitional Auction). The ISO shall work with the auctioneer to conduct the Optimum Power Flows in each round of the Auction, until such time as the ISO determines that the auctioneer has gained sufficient expertise to conduct those Optimum Power Flows without direct ISO involvement. The ISO will continue to verify that the Optimum Power Flows calculated independently by the auctioneer in each round of the Auction, correspond to a simultaneously feasible Power Flow as described in Section 9.7 below. The ISO shall notify the Transmission Owners if: (1) the Optimum Power Flow results calculated by the auctioneer are inaccurate; (2) the Optimum Power Flow is not calculated in accordance with the correct procedure; or (3) in the ISO's objective opinion, the auctioneer is unable to conduct the required Optimum Power Flows adequately. The ISO shall dismiss and replace the auctioneer if in the ISO's reasonable judgement, the auctioneer is unable to conduct an Optimum Power Flow accurately and properly for the NYS Transmission System.

Additionally, the ISO will determine the information pertaining to the Auction to be made available to Auction participants over the OASIS and/or the auctioneer's information system and publish information on its OASIS accordingly. The ISO will identify the details to be included in development of the Auction software and arrange for development of the software.

The ISO will evaluate each bidder's ability to pay for TCCs. As a result of this evaluation, the ISO will state a limit before the Auction on the value of the TCCs that the entity may be awarded in Direct Sales or in the Auction, and collect signed statements from each entity bidding into the Auction committing that entity to pay for any TCCs that it is awarded in the Auction. Neither the ISO nor the auctioneer shall reveal the Bid Prices submitted by any bidder in the Auction until six months following the date of the Auction.

Upon completion of the Auction, the ISO will collect payment for all TCCs awarded for each round of the Auction. The ISO will disburse the revenues collected from the sale of TCCs to the Primary Holders upon completion of the Auction process. Each holder of a TCC that offers that TCC for sale in a round of the Auction shall be paid the Market Clearing Price for each TCC sold in that round by that holder. All remaining Auction revenues from each round (in Stage 1 or Stage 2) of the Auction shall be allocated among the Transmission Owners using the Interface MW-Mile Methodology, as described in Attachment N to the ISO OATT. This allocation will be performed separately for each round of the Auction.

9.3 Responsibilities of the Auctioneer

The auctioneer shall be capable of completing the Auction within the time frame specified in this Attachment. The auctioneer will establish an auditable information system to facilitate analysis and acceptance or rejection of Bids, and to provide a record of all Bids and provide all necessary assistance in the resolution of disputes that arise from questions regarding the acceptance, rejection, award and recording of Bids. The auctioneer will establish a system to communicate Auction-related information to all Auction participants between rounds of the Auction. (This last requirement will not apply to single-round Auctions.)

The auctioneer will receive Bids to buy TCCs from any entity that meets the eligibility criteria established in Section 11.0 of the ISO OATT and will implement the Auction bidding rules established by the ISO.

The auctioneer must possess the skills to solve Optimum Power Flows for the NYS Transmission System; properly utilize an Optimum Power Flow program to determine the set of winning Bids for each round of the Auction; and calculate the Market Clearing Price of all TCCs at the conclusion of each round of the Auction, in the manner described in this Attachment, and communicate winning Bids to the ISO.

The auctioneer shall have liability insurance sufficient to compensate and indemnify and defend the ISO from and against any claims, financial losses or injury resulting from the auctioneer's acts or omissions.

9.4 Responsibilities of each Bidder

Each bidder shall submit the following information with its Bids: (i) the number of TCCs for which an offer to purchase is made, (ii) the Bid Price (in $/TCC) which represents the maximum amount the bidder is willing to pay for the TCC (Bid Prices may be negative, indicating that a bidder would have to be paid in order to accept a TCC); (iii) the location of the Point of Injection and the Point of Withdrawal for the TCC to which the Bid applies (these locations may be any locations for which the ISO calculates an LBMP); (iv) if the Auction is an Initial Auction, the duration in multiples of Capability Periods of the TCC for which the bidder is bidding; and (v) if the Auction is an End-State Auction, the points in time at which the TCC bid upon begins to be valid (which must be the beginning of a Capability Period) and at which the TCC Bid upon ceases to be valid (which must be the end of a Capability Period, and which may not extend beyond the last point in time for which TCCs will be available in that Auction). Additionally, if the ISO offers

TCCs for sale that are valid in sub-periods (e.g., peak or off-peak TCCs), this information must also be provided by the bidder.

Each bidder must submit such information to the ISO regarding the bidder's creditworthiness as the ISO may require, along with a statement signed by the bidder, representing that the bidder is financially able and willing to pay for the TCCs for which it is bidding. The aggregate value of the Bids submitted by any bidder into the Auction shall not exceed that bidder's ability to pay or the maximum value of bids that bidder is permitted to place, as determined by the ISO (based on an analysis of that bidder's creditworthiness).

Each bidder must pay the Market Clearing Price for each TCC it is awarded in the Auction.

9.5 Selection of Winning Bids and Determination of the Market Clearing Price

The auctioneer shall determine the winning set of Bids in each round of the Auction as follows: (i) the auctioneer shall use an Optimal Power Flow program with the initial assumptions identified by the ISO; (ii) the Optimal Power Flow shall use the same Reference Bus and system security Constraints assumptions as used by the ISO; (iii) the auctioneer shall select the set of Bids that maximizes the value of the TCCs awarded to the winning bidders; (iv) the aggregate market value of the TCCs awarded to each bidder shall not exceed that bidder's ability to pay, since each bidder is not allowed to Bid more than its ability to pay as determined by the ISO; and (v) the selected set of Bids must be simultaneously feasible as described in this Attachment.

In the Initial Auction, if the ISO elects to perform separate Auctions for peak and off-peak TCCs, the procedure used to select winning Bids in a peak Auction will not depend on winning Bids selected in an off-peak Auction; nor shall the procedure used to select winning Bids in an off-peak Auction depend on winning Bids selected in a peak Auction.

The Market Clearing Price for each TCC in each round of Stages 1 and 2 of an Auction shall be determined using a similar algorithm to that used to determine LBMPs (see

Attachment J to the ISO OATT). The Market Clearing Price for each TCC shall be based on the lowest winning Bid made in that round for that TCC (or for other TCCs if injections and withdrawals corresponding to those TCCs would have the same impact on flows over congested Interfaces as injections and withdrawals corresponding to that TCC).

9.6 Billing

Charges for TCCs awarded in the Auction shall be billed upon completion of the Auction process.

9.7 Simultaneous Feasibility

The set of winning Bids selected in each round of Stage 1 shall correspond to a simultaneously feasible Power Flow, with the exception of the End-State Auction. In the End-State Auction, multiple Power Flows will be conducted in each round. One Power Flow will correspond to each of the Capability Periods for which TCCs are offered for Sale in that Auction. The set of winning bids for any given round of an End-State Auction shall correspond to a simultaneously feasible Power Flow in each of the Capability Periods for which TCCs are available in the Auction. References in the remainder of this Section to “Power Flow” shall, in the case of the End-State Auction, be understood as referring to the “Power Flow for each of the Capability Periods for which TCCs are available in the Auction.”

The Power Flow must be able to accommodate in each round injections and withdrawals corresponding to each of the following TCCs and Grandfathered Rights: (i) TCCs not offered for sale in Stage 1, including: (a) Grandfathered TCCs or TCCs purchased in a previous Auction that have been not offered for sale in Stage 1 of the Auction; and (b) Residual TCCs sold in Direct Sales directly by Transmission Owners and not offered for sale in Stage 1 of the Auction by their purchaser; (ii) Grandfathered Rights; (iii) TCCs awarded in earlier rounds of Stage 1 (if applicable); and (iv) TCCs awarded in the current round of Stage 1. Each injection and withdrawal associated with TCCs and Grandfathered Rights will be multiplied by a scaling factor which apportions the transmission capacity available in Stage 1 among each of the rounds in Stage 1. The use of this scaling factor is illustrated in the example in Section 9.9 below.

The set of winning Bids selected in each round of Stage 2 shall correspond to a simultaneously feasible Power Flow that can accommodate injections and withdrawals corresponding to the following: (i) TCCs not offered for sale in the current round of Stage 2 of the Auction which include (a) Grandfathered TCCs not sold in Stage 1 or any earlier round of Stage 2 that are not offered for sale in the current round, (b) Residual TCCs sold in Direct Sales by the Transmission Owners (that are not offered for sale in the current round or any earlier round of the Auction by their purchaser), and (c) TCCs sold in Stage 1, in earlier rounds of Stage 2, or in previous Auctions which have not been resold in subsequent Auctions and are not offered for sale in the current round; (ii) Grandfathered Rights; and (iii) TCCs awarded in the current round of Stage 2.

A set of injections and withdrawals shall be judged simultaneously feasible if it would not cause any thermal, voltage, or stability violations within the NYCA for base case conditions or any monitored contingencies.

When performing the above Power Flows, injections for TCCs that specify a Zone as the injection location will be modeled as a set of injections at each Load bus in the injection Zone (Generator buses will be used until the ISO's software can accommodate Load buses) equal to the product of the number of TCCs and the ratio of Load served at each bus to Load served in the Zone, based on the bus Loads used in calculating zonal LBMPs.

When performing the above Power Flows, withdrawals for TCCs that specify a Zone as the withdrawal location will be modeled as a set of withdrawals at each Load bus in the withdrawal Zone (Generator buses will be used until the ISO's software can accommodate Load buses) equal to the product of the number of TCCs and the ratio of the Load served at each bus to the total Load served in the Zone based on the ISO's estimate of the bus Loads used in calculating the Zonal LBMPs.

The Power Flow simulations shall take into consideration the effects of parallel flows on the Transfer Capability of the NYS Transmission System when determining which sets of injections and withdrawals are simultaneously feasible.

9.8 Information to be Made Available to Bidders

The ISO shall provide, or require the auctioneer to provide, over the ISO's OASIS and/or the auctioneer's information system, the expected non-simultaneous Total Transfer Capability for each Interface (as displayed on the OASIS).

The auctioneer shall make the following information available before each Initial, End-State, or Reconfiguration Auction:

(i) for each Generator bus, External bus and Load Zone for the previous ten (10) Capability Periods, if applicable, (A) the average Congestion Component of the LBMP, relative to the Reference Bus, and (B) the average Marginal Losses Component of the LBMP, relative to the Reference Bus;

(ii) for the previous two Capability Periods, (A) historical flow histograms for each of the closed Interfaces, and (B) historically, the number of hours that the most limiting facilities were physically constrained;

(iii) (A) Power Flow data to be used as the starting point for the Auction, including all assumptions, (B) assumptions made by the ISO relating to transmission maintenance outage schedules, (C) all limits associated with transmission facilities, contingencies, thermal, voltage and stability to be monitored as Constraints in the Optimum Power Flow determination, and (D) the ISO summer and winter operating study results (non-simultaneous Interface Transfer Capabilities);

(iv) between each round of bidding during the Auction, for all bidders bidding in subsequent rounds, the Market Clearing Price, stated relative to the Reference Bus for each Generator bus, External bus and Load Zone;

(v) for each TCC awarded in each round, (A) the number of TCCs awarded, (B) the Points of Injection and Withdrawal for that TCC, (C) the Market Clearing Price for the TCC, and (D) the Auction participant awarded the TCC.

Items (i) through (iv) above shall be made available separately for peak and off-peak periods, if peak and off-peak TCCs will be separately available for purchase in the upcoming Auction.

9.9 Auction Example

The following example is for purposes of illustration. For the purposes of this example, assume that the ISO has determined that one-fourth of the transmission capacity that has been offered for sale in Stage 1 will be available to support TCCs purchased in each of four Stage 1 rounds.

The example illustrates a sub-auction of an Initial Auction. It can also be used to illustrate the operation of the End-State Auction, if one makes the additional assumption that all bidders have offered to purchase TCCs of the same length, and that all sellers have released TCCs of that same length.

Round 1a

In the first round of Stage 1 (round 1a), suppose that 100 TCCs from location X to location Y are offered for sale into Stage 1 of the Auction, and four (4) Bids have been received by the auctioneer for TCCs from location X to location Y, as follows:

Company A Bids for 50 TCCs @ $5.00/TCC

Company B Bids for 50 TCCs @ $4.00/TCC

Company C Bids for 20 TCCs @ $2.00/TCC

Company D Bids for 10 TCCs @ $1.00/TCC

For the sake of simplicity, assume in this example that 100 TCCs from location X to location Y will actually be allocated in Stage 1 of the Auction, although in practice, the number of TCCs that would be available between those locations in Stage 1 would depend on the number of TCCs that were allocated between other locations on the Transmission System, and could actually change from round to round within Stage 1.

Since one-fourth of the transmission capacity that has been offered for sale in Stage 1 is to be sold in round 1a, the number of TCCs specified in each of the Bids above is multiplied by a scaling factor of four:

Company	Scaled Number of TCCs Company Offers to Purchase	Bid Price
A	200	$5/TCC
B	200	$4/TCC
C	80	$2/TCC
D	40	$1/TCC

Since 100 TCCs are available from location X to location Y, Company A would be the only company that would receive TCCs in the current round, because its Bid is the highest Bid, in $/TCC terms, and its scaled Bid for 200 TCCs exceeds the 100 TCCs available. Company A would be the winning bidder, and the Market Clearing Price for TCCs in this round would be Company A's Bid of $5/TCC.

However, Company A would not actually be awarded 100 TCCs. Each winning Bid in each Stage 1 round will be divided by the scaling factor used for that round to determine the number of TCCs that would be awarded to each winning bidder. Thus, Company A's winning Bid for 100 scaled TCCs would be converted into an actual award of 100 TCCs / 4 = 25 TCCs. Company A would be awarded 25 TCCs at the conclusion of round 1a, at a price of $5/TCC.

Round 1b

Three-fourths of the TCCs that have been offered for sale in Stage 1 remain available after round 1a, so if one-fourth of all the TCCs that have been offered for sale in Stage 1 and to be sold in the second round of Stage 1 (round 1b), then one-third of the TCCs that have been offered for sale in Stage 1 remaining after round 1a must be sold in round 1b (since 1/3 x 3/4 = 1/4). Consequently, the scaling factor for round 1b would be three. We have assumed that 75 TCCs will now be available from location X to location Y in round 1b, once the 25 TCCs awarded to Company A in round 1a have been taken into account. Bids (including scaled Bids) into round 1b for TCCs between these locations are given below.

Company	Number of TCCs Company Offers to Purchase	Scaled Number of TCCs Company Offers to Purchase	Bid Price
A	30	90	$6/TCC
B	50	150	$5/TCC
C	20	60	$3/TCC
D	10	30	$2/TCC

Since 75 TCCs are available from location X to location Y, Company A would again be the only company that would receive TCCs in this round, because its Bid is the highest Bid, in $/TCC terms, and its scaled Bid for 90 TCCs exceeds the 75 TCCs available. Company A would be the winning bidder, and the Market Clearing Price for TCCs in this round would be Company A's Bid, which has increased to $6/TCC in this round.

However, Company A's winning Bid for 75 scaled TCCs would be converted into an actual award of 75 TCCs / 3 = 25 TCCs. Company A would be awarded 25 TCCs at the conclusion of round 1b, at a price of $6/TCC.

Round 1c

Half of the TCCs that have been offered for sale in Stage 1 remain available after rounds 1a and 1b, so half of the remaining the TCCs that have been offered for sale in Stage 1 must be sold in the third round of Stage 1 (round 1c), making the scaling factor for round 1c equal to two. We have assumed that 50 TCCs will now be available from location X to location Y in round 1c, once the 50 TCCs awarded to Company A in rounds 1a and 1b have been taken into account. Bids (including scaled bids) into round 1c for TCCs between these locations are given below.

Company	Number of TCCs Company Offers to Purchase	Scaled Number of TCCs Company Offered to Purchase	Bid Price
A	10	20	$5/TCC
B	40	80	$6/TCC
C	10	40	$2/TCC
D	10	20	$7/TCC

Since 50 TCCs are available between these locations, Company D, which now has the highest Bid, would be awarded 20 scaled TCCs, and Company B, which now has the second-highest Bid, would receive the next 30 scaled TCCs. The Market Clearing Price for TCCs in this round would be $6/TCC, Company B's Bid.

However, the winning bids would be converted into actual awards of 20 TCCs / 2 = 10 TCCs to Company D, and 30 TCCs / 2 = 15 TCCs to Company B, each at a price of $6/TCC.

Round 1d

All of the TCCs that have been offered for sale in Stage 1 that remain available after rounds 1a, 1b and 1c will be sold in the fourth round of Stage 1 (round 1d), so the scaling factor for round 1d would be one. In other words, there would be no scaling in round 1d. We have assumed that 25 TCCs will now be available from location X to location Y in round 1b, once the 75 TCCs awarded in rounds 1a, 1b and 1c have been taken into account. Bids into round 1d for TCCs between these locations are given below. (Note that Companies A and D have dropped out of the Auction at this point and Company E has entered the Auction, illustrating that there is no requirement for bidders in earlier rounds to Bid into later rounds or for bidders in later rounds to Bid into earlier rounds.)

Company	Number of TCCs Company Offers to Purchase	Bid Price
B	15	$5/TCC
C	20	$2/TCC
E	20	$10/TCC

Since 25 TCCs are available between these locations, Company E, which now has the highest Bid, would be awarded 20 TCCs, and Company B, which has the second-highest Bid, would receive the last 5 TCCs. The Market Clearing Price for TCCs in this round would be $5/TCC, Company B's Bid.

Stage 1 Summary

TCCs awarded from location X to location Y in Stage 1, and the prices paid for those TCCs, are as follows:

Company	Round	TCCs Awarded	Price
A	1a	25	$5/TCC
A	1b	25	$6/TCC
B	1c	15	$6/TCC
B	1d	5	$5/TCC
D	1c	10	$6/TCC
E	1d	20	$5/TCC

In this example, all revenues from this Auction would be paid to the holders of the 100 Residual TCCs from location X to location Y that released those TCCs for sale into Stage 1 of the Auction.

Stage 2

In the first round of Stage 2 (round 2a), assume that Company F, which holds 50

TCCs from location X to location Y (that it received as a result of a grandfathered transmission agreement) releases those TCCs for sale into the Auction. In addition, suppose that Company E releases the 20 TCCs from location X to location Y that it purchased in Stage 1 for sale into round 2a of the Auction, so that a total of 70 TCCs from location X to location Y have been released for sale into round 2a. Although it is possible that more or fewer than 70 TCCs from location X to location Y will actually be sold, depending on Bids made for TCCs between other locations, assume for purposes of the example that only 70 TCCs between these two locations are actually sold in round 2a.

Bids into round 2a are as follows:

Company	Number of TCCs Company Offers To Purchase	Bid Price
B	40	$5/TCC
C	40	$4/TCC
G	40	$9/TCC

Company G, the highest bidder, would be awarded 40 TCCs, and Company B, the second highest bidder, would be awarded the remaining 30 TCCs. The Market Clearing Price in round 2a would be Company B's Bid, $5/TCC, so the winning bidders in round 2a would pay $5/TCC for the TCCs they are awarded in round 2a. Companies E and F would be paid $5/TCC for each TCC from location X to location Y that they released for sale into the Auction.

Subsequent rounds in Stage 2 would proceed in the same manner as round 2a.

V. ALLOCATION OF TCC SALES REVENUES, EXCESS CONGESTION RENTS AND CONGESTION RENT SHORTFALL

1.0 Allocation and Distribution of Revenues

The ISO shall allocate and distribute all revenues resulting from: (i) the accumulated Excess Congestion Rents; (ii) the sale of Residual TCCs in the Centralized TCC Auction; and (iii) the sale of Grandfathered TCCs in the Centralized TCC Auction. Also, the ISO shall collect all Congestion Rent Shortfalls.

2.0 Distribution of Revenues from Sale of Grandfathered TCCs in the Centralized TCC Auction

The ISO shall distribute to each holder of a TCC selling that TCC in the Centralized TCC Auction the Market Clearing Price of that TCC in the round of the Centralized Auction in which that TCC was sold. In the event a Grandfathered TCC is terminated by mutual agreement of the parties to the Grandfathered ETA prior to the conditions specified within Attachments K and L of the ISO OATT, then the ISO shall distribute the revenues from the sale of the newly created Residual TCCs, which correspond to the terminated Grandfathered TCCs, in the Centralized TCC Auction directly back to the Transmission Owner identified in Attachment L of the ISO OATT, until such time the conditions specified within Attachments K and L of the ISO OATT are met. Upon such time that the conditions within Attachments K and L of the ISO OATT are met, the ISO shall allocate the revenues from the sale of the newly created Residual TCCs, which correspond to terminated Grandfathered TCCs, in the Centralized Auction in accordance with Section 3.2, below.

3.0 Allocation of Revenues from the Sale of Residual TCCs, Excess Congestion Rents and Congestion Rent Shortfalls

3.1 The ISO shall allocate the Excess Congestion Rents and Congestion Rent Shortfalls using the Interface MW-Mile Methodology based on the Power Flows used in the Centralized TCC Auction.

3.2 The ISO shall allocate the revenues from the sale of Residual TCCs as follows:

- Revenues associated with Residual TCCs that were determined before the first Centralized TCC Auction was conducted, shall be distributed directly to each Primary Owner for the duration of the LBMP Transition Period.
- Revenues associated with all other Residual TCCs, including Residual TCCs determined during the Centralized TCC Auction and TCCs released from ETAs when they are terminated (refer to Attachment M of the ISO OATT), shall be allocated back to the Transmission Providers using the Interface MW-Mile

Methodology.

3.3 Where the Interface MW-Mile Methodology applies, the ISO shall allocate an amount equivalent to the product of (1) the IMW (i) coefficient, and (2) either the Excess Congestion Rent revenue, Congestion Rent Shortfall or the revenue from the Centralized TCC Auction.

3.4 The IMWM(i) coefficient is calculated as follows:

$$IMWM(i) = \sum_{j=1}^{TCC} \sum_{k=1}^{10} \left[\left(\frac{mwmile_{ik}}{\sum_{i=1}^{TrO} mwmile_{ik}} \right) \bullet \left(\frac{CC_{jk}}{\sum_{k=1}^{10} CC_{jl}} \right) \right]$$

Where,

- *i* = Transmission Owner for which the coefficient is calculated.
- *j* = TCC for which the coefficient is calculated.
- *k* = Interface for which the coefficient is calculated.
- *l* = Interface for which the coefficient is calculated.
- TrO = Number of Transmission Owners.
- TCC = Number of TCCs sold in the Centralized TCC Auction.
- $mwmile_{ik}$ = Total of the megawatts times miles of circuits in zones associated with Interface *k* for Transmission Owners *i*.

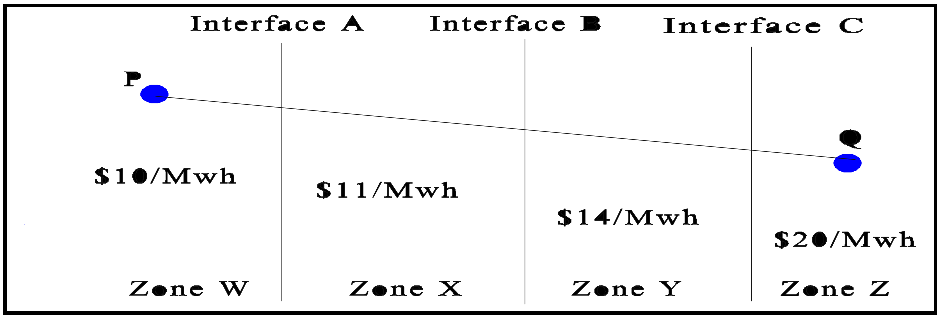
CC_{jk} = Congestion associated with a TCC *j* across Interface *k*.
CC_{jl} = Congestion associated with a TCC*j* across Interface *l*.

The first term of the above equation shall be referred to as the MW-mile component and the second term of the above equation shall be referred to as the Congestion Component. When calculating the IMWM(i) coefficient for distribution of revenues from the Centralized TCC Auction, the ISO shall determine the Congestion Component across Interfaces using the Power Flow used in the same Centralized TCC Auction in which the TCCs were sold.

An exception to the above procedure, is that the MW-Mile component of the IMWM(i) coefficient associated with the Con Edison -LIPA Interface used to allocate Excess Congestion Rents or Congestion Rent Shortfalls shall be based on the firm contractual agreements among the parties that own transmission facilities on this Interface.

When calculating the IMWM(i) coefficient for distribution of Excess Congestion Rents, or Congestion Rent Shortfalls, the ISO shall replace the Congestion Component values with the Transmission Fund (T-fund) percentages in effect under the NYPP Agreement at the time the ISO OATT becomes effective until the first Centralized TCC Auction.

3.5 Example of IMWM(i) Coefficient Calculation



GIVEN:

Auctioned a single 100MW TCC From P TO Q

TCC REVENUES = $1000

THREE INTERFACES: A,B,C

FOUR ZONES: W,X,Y,Z

GENERATION in ZONE W

LOAD in ZONE Z (Losses are ignored)

LBMP $/Mwh: W= $10, X= $11, Y= $14, and Z= $20

Zone	Company	MW-Miles
w	1	100
w	2	100
x	1	200
x	2	400
y	1	100
y	2	100
z	1	200
z	2	600

The IMWM(i) coefficient:

COMPANY 1:

IMWM(1) = ((100+200)/800) * (1/10) ==> Interface A: Zone W, X

+ ((200+100)/800) * (3/10) ==> Interface B: Zone X,Y

+ ((100+200)/1000) * (6/10) ==> Interface C: Zone Y, Z

= .0375 + .1125 + .18 = .33

COMPANY 2:

IMWM(2) = ((100+400)/800) * (1/10) ==> Interface A: Zone W,X

+ ((400+100)/800) * (3/10) ==> Interface B: Zone X,Y

+ ((100+600)/1000) * (6/10) ==> Interface C: Zone Y, Z

= .0625 + .1875 + .42 = .67

REVENUES for COMPANY 1 = .33 * $1000 = $330

REVENUES for COMPANY 2 = .67 * $1000 = $670

VI. CONGESTION PAYMENTS MADE TO PRIMARY HOLDERS

1.0 The ISO shall make Congestion payments to the Primary Holders as follows:

Congestion Payment ($/hr)= $(CC_{POW} – CC_{POI})\ TCC_{MW}$

Where:

CC_{POW} = Congestion Component ($/MWh) at the Point of Withdrawal (“POW”)

CC_{POI} = Congestion Component ($/MWh) at the Point of Injection (“POI”)

TCC_{MW} = The number of TCCs in MW from POI to POW

(See Attachment J to the ISO OATT for the calculation of the Congestion Component of the LBMP price at either the POI or the POW).

2.0 The ISO shall pay the Primary Holders for the Congestion payment from revenues collected from: (i) the Congestion Components at the POWs minus the Congestion Components at the POIs multiplied by the Energy associated with the POWs and POIs in the LBMP Markets; (ii) the Congestion Component of the TUCs which apply to Bilateral Transactions; and (iii) funds recovered through the TSC of the Transmission Owners pursuant to Section 3 below.

3.0 If revenues collected in 2.0 are in excess of, or are insufficient to cover, the entire Congestion payments, the ISO shall allocate the Excess Congestion Rents or Congestion Rent Shortfall to the Transmission Owners in accordance with Attachment K for creditor collection through their respective TSC or NTAC.

Attachment B
Table 1

Table 1 - TCC Reservations Subject to MW Reduction

					Sum	Win	Interface Allocations - Summer Period									
	Reservation Holder	Name	From	To	MW	MW	DE	WC	VE	MoS	TE	US	UC	MS	DS	CE-LI
1	Con Edison	Bowline	Bowline	Con Edison	801	801							801	768	584	
2	Con Edison	ST4 HQ	Con Ed - North	Con Edison	400	208							400	384	292	
3	Con Edison	Gilboa	Con Ed - North	Con Edison	125	125							125	120	91	
4	Con Edison	Roseton	Roseton-GN1	Con Edison	480	480							480	461	351	
5	Con Edison	Corinth	Con Ed - North	Con Edison	134	134							134	129	98	
6	Con Edison	Sithe	Con Ed - North	Con Edison	837	837							837	803	611	
7	Con Edison	Selkirk	Selkirk	Con Edison	265	265							265	254	193	
8	Con Edison	IP2	Indian Pt 2	Con Edison	893	893								893	679	
9	Con Edison	IP3	Indian Pt 3	Con Edison	108	108								108	82	
10	Con Edison	IP Gas Turbine	IP GT-Buchanan	Con Edison	48	48								48	36	
11	NMPC	NMP1	NMP1	NMPC - East	610	610			610		610					
12	NMPC	NMP2	NMP2	NMPC - East	460	460			460		460					
13	NMPC	Hydro North	Colton	NMPC - East	110	110					110					
14	NYSEG	Homer City	Homer City	NYSEG - Cent.	863	863	863	863								
15	NYSEG	Homer City	Homer City	NYSEG - West	100	100										
16	NYSEG	Allegheny 8&9	Pierce Rd 230kV	NYSEG - Cent.	37	37	37	37								
17	NYSEG	BCLP	Homer City	NYSEG - Cent.	80	80	80	80								
18	NYSEG	LEA (Lockport)	NYSEG - West	NYSEG - Cent.	100	100	100	100								
19	NYSEG	Gilboa	Gilboa	NYSEG - Mech	99	99										
20	SENY (2) (4)	Niagara OATT Reservation	Niagara	Con Edison	422	422	422 [3]	422 [3]	422 [3]		422 [3]	422 [3]	422 [3]	422 [3]	422 [3]	
21	SENY (2) (4)	St. Lawrence OATT Reserv.	St. Lawrence	Con Edison	178	178				178 [3]	178 [3]	178 [3]	178 [3]	178 [3]	178 [3]	

Notes: 1 Interface Designations: DE - Dysinger East; WC - West Central; VE - Volney East; MoS - Moses South; TE - Total East; US - UPNY/SENY; UC - UPNY/Con Ed; MS - Millwood South; DS - Dunwoodie South; CE-LI - Con Ed/LILCO

2. Subject to NYPA's obtaining non-discriminatory long term firm reservation through 2017 under their OATT.

3. NYPA's TCCs allocated to their SENY Governmental Load Customers, across UPNY/Con Ed, Millwood South and Dunwoodie South will be up to 600 MW, or amounts otherwise available to NYPA pursuant to the grandfathered rights applicable under the Planning & Supply and Delivery Services Agreement between NYPA and Con Edison dated March 1989.

4. NYPA's TCCs allocated to their SENY Governmental Load Customers will terminate on the earlier of December 31, 2017 or when NYPA no longer has an obligation to serve any SENY Loads or the retirement or sale of both IP#3 and Poletti.

ATTACHMENT C

FORMULAS FOR DETERMINING MINIMUM GENERATION AND START-UP PAYMENTS

Minimum Generation and Start-Up Payment = Day-Ahead Minimum Generation and Start-Up Payment + Real-Time Market Minimum Generation and Start-Up Payment;

Day-Ahead Minimum Generation and Start-Up Payment =

$$\sum_{g \epsilon G} \max \left[\sum_{i=1}^{24} \left(\int_{MGH_{gi}^{DA}}^{EH_{gi}^{DA}} C_{gi}^{DA} + MGC_{gi}^{DA}\ MGH_{gi}^{DA} + SUC_{gi}^{DA}\ NSUH_{gi}^{DA} - LBMP_{gi}^{DA}\ EH_{gi}^{DA} - NASR_{gi}^{DA} \right),\ 0 \right]$$

Real-Time Market Minimum Generation and Start-Up Payment =

$$\sum_{g \epsilon G} \max \left[\sum_{i=1}^{N} \left(\int_{EI_{gi}^{DA}}^{EI_{gi}^{RT}} C_{gi}^{RT} + MGC_{gi}^{RT} (MGI_{gi}^{RT} - MGI_{gi}^{DA}) + SUC_{gi}^{RT} (NSUI_{gi}^{RT} - NSUI_{gi}^{DA}) - LBMP_{gi}^{RT}(EI_{gi}^{RT} - EI_{gi}^{DA}) - (NASR_{gi}^{TOT} - NASR_{gi}^{DA}) \right),\ 0 \right]$$

Where:

G	=	set of Generators;
EH_{gi}^{DA}	=	Energy scheduled Day-Ahead to be produced by Generator g in hour i;
MGH_{gi}^{DA}	=	Energy scheduled Day-Ahead to be produced by minimum generation segment of Generator g in hour i;
C_{gi}^{DA}	=	Bid cost curve made by Generator g in the Day-Ahead Market for hour i;
MGC_{gi}^{DA}	=	minimum generation cost Bid by Generator g for hour i in the Day-Ahead Market;
SUC_{gi}^{DA}	=	start-up cost bid by Generator g in hour i into Day-Ahead Market;
$NSUH_{gi}^{DA}$	=	number of times Generator g is scheduled Day-Ahead to start up in hour i;
$LBMP_{gi}^{DA}$	=	Day-Ahead LBMP at Generator g's bus in hour i;
N	=	number of SCD intervals in 24-hour day;
EI_{gi}^{RT}	=	metered Energy produced by Generator g in SCD interval i;
EI_{gi}^{DA}	=	Energy scheduled in the Day-Ahead Market to be produced by Generator g in SCD interval i;
$NASR_{gi}^{DA}$	=	Net Ancillary Services revenue paid to Generator g as a result of having been committed to produce Energy for the LBMP Market and/or Ancillary Services Day-

Ahead to operate in hour i is computed by summing the following: (1) Voltage Support payments received by that Generator for that hour, if it is not a Supplier of Installed Capacity and has been scheduled to operate in that hour; (2) Regulation payments made to that Generator for all Regulation it is scheduled Day-Ahead to provide in that hour, adjusted for that Generator's performance that hour, less that Generator's Day-Ahead Bid to provide that amount of Regulation in that hour (unless the Bid exceeds the payments that Generator receives for providing Regulation that was committed to produce Energy for the LBMP Market and/or Ancillary Services Day-Ahead, in which case this component shall be zero); and (3) Availability payments made to that Generator for providing Spinning Reserve in that hour if it is committed Day-Ahead to provide Spinning Reserve in that hour, less that Generator's Day-Ahead Bid to provide Spinning Reserve in that hour.

C_{gi}^{RT} = Bid cost curve made by Generator g in the Real-Time dispatch for the hour that includes SCD interval i;

MGI_{gi}^{RT} = metered Energy produced by minimum generation segment of Generator g in SCD interval i;

MGI_{gi}^{DA} = Energy scheduled Day-Ahead to be produced by minimum generation segment of Generator g in SCD interval i;

MGC_{gi}^{RT} = minimum generation cost bid by Generator g in the Real-Time Market for the hour that includes SCD interval i;

SUC_{gi}^{RT} = start-up cost bid by Generator g in hour i into Real-Time dispatch;

$NSUI_{gi}^{RT}$ = number of times Generator g started up in SCD interval i;

$NSUI_{gi}^{DA}$ = number of times Generator g is scheduled Day-Ahead to start up in SCD interval i;

$LBMP_{gi}^{RT}$ = Real-Time LBMP at Generator g's bus in SCD interval i.

$NASR_{gi}^{TOT}$ = Net Ancillary Services scheduled revenue paid to Generator g as a result of either having been committed Day-Ahead to operate in hour i or having operated in hour i is computed by summing the following: (1) Voltage Support payments received by that Generator for that hour, if it is not a supplier of Installed Capacity; (2) Regulation Service payments made to that Generator for that hour, adjusted for that Generator's performance in that hour, less the Bid(s) placed by that Generator to provide Regulation in that hour at the time it was committed to produce Energy for the LBMP Market and/or Ancillary Services to do so (unless the Bid(s) exceeds the payments that Generator receives for providing Regulation Sevice, in which case this component shall be zero); (3) Availability payments made to that Generator for providing Spinning Reserve in that hour, less the Bid placed by that Generator to provide Spinning Reserve in that hour at the time it was scheduled to do so; (4) Payments made to that Generator in that hour for Energy in excess of that Generator's actual Energy injections (such payments may be made to providers of Regulation Service whenever the SCD signals sent to those Generators exceed the

AGC Base Point Signals sent to those Generators); and (5) Lost Opportunity Cost payments made to that Generator in that hour as a result of reducing that Generator's output in order for it to provide Voltage Support or Spinning Reserve.

Time periods including reserve pick-ups, and time periods following a reserve pick-up in which the dispatch of a given Generator is contrained by its downward ramp rate, will not be included in the above calculation of supplemental payments for that Generator.

Also, in the above calculations, if a Supplier of Regulation Service moves above its SCD Base Point as a result of responding to the AGC Base Points sent to it, its Bid cost for producing that Energy will be deemed equal to its Bid at its SCD Base Point.

Supplemental payments to units that trip before completing their minimum run-time (for units that were not scheduled to run Day-Ahead) or before running for the number of hours they were scheduled to operate (for units scheduled to run Day-Ahead) may be reduced by the ISO, per ISO Procedures.

Penalty charges resulting from failure to provide an Ancillary Service will not be taken into account when calculating supplemental payments for that Supplier.

Generators with start-up times of greater than twenty-four (24) hours will have their start-up cost Bids equally prorated over the course of each day included in their start-up period. Consequently, units whose start-ups are aborted will receive a pro-rated portion of those payments, based on the portion of the start-up sequence they have completed (e.g., if a unit with a seventy-two (72) hour start-up time has its start-up sequence aborted after forty-eight (48) hours, it would receive two-thirds (2/3) of its start-up cost Bid).

ATTACHMENT D

DATA REQUIREMENTS FOR INTERNAL GENERATORS FOR LBMP BIDDERS

Attachment D
Table D-1
Data Requirements for Internal Generators for LBMP Bidders

Data Item	Cat.	Bid Parameters	Variability		Comments
Company Name	G	--	Static	Required	Parent Organization
Generator Name/No.	G	--	Static	Required	
Generator Unit Code/ID	G	--	Static	Required	Unique code which identifies the generator to the ISO
Bus	G	Bus No.	Static	Required	Specific location of Generator within the NYCA
Submitted By	G	Name	May vary	Required	Organization submitting bid. Multiple organization can be authorized to submit bids with the ISO accepting the most recent. A single organization must be specified to receive invoices from the ISO.
DMNC (Summer & Winter)	P/G	MW	Static	Required	Dependable Maximum Net Capability. Confirmed by test for units with installed capacity contracts, or historical production data.
Power Factor	P/G	MW/MVA	Static	Optional	Generator's tested Power Factor for producing reactive power (MVArs) at normal high operating limit MW output level. Provided it is at least 90% of DMNC. This is required for Generators receiving Voltage Support Payments.
Installed Capacity Contracts	G	MW	May vary	Required	Installed Capacity contracts in effect with LSEs within the NYCA. The ISO may limit maximum and/or minimum amounts of Installed Capacity by location due to reliability Constraints.
Upper Operating Limit	C/D	MW	May change by hour for Day-Ahead	Required	Maximum output of a unit that could be expected in any hour of the following operating day. The ISO must be informed of a limit change that results in less capability.
Normal Response Rate (NRR)	P/C/D	MW/min.	May vary	Required	To be provided as an expected response rate for SCD. The minimum acceptable response rate is 1% of a unit's gross output per minute.
Regulation Response Rate (RRR)	P/C/D	MW/Min.	Same as NRR	Optional	To be provided as an expected response for regulation. If RRR differs from NRR, the total expected response rate is restricted to the maximum of the two rates.
Emergency Response Rate (ERR)	P/C/D	MW/Min. **or** Piecewise linear curve with MW Output as independent variable and MW/Min. as dependent variable	Same as NRR	Optional	To be provided as expected response for reserve pickups; ERR must at least equal NRR. If ERR is reduced, then unit will be subject to a performance penalty if called upon. ERR for Class B Reserve bidders must at least equal the static NRR from Pre-Qualification data. Bidders must inform ISO of all changes to ERR.
Reactive Power Capability	P/G	Piecewise linear curve with MW as independent variable and +/- MVArs as dependent variable	Static	Optional	Update as changed.

Notes:
Internal Generators LBMP bidders are located within the NYCA.
Cat. = Data Categories: **G** = General; **P** = Pre-Qualification; **C** = Commitment; **B** = Balancing; **D** = Dispatch; **I** = Installed Capacity.
Static Data remains relatively constant over the lifetime of bids but can be changed.
General Data may be provided electronically or by mail, but requires a confirmation or Pre-Qualification process by the ISO.
Some data will require substantiation by a test; actual data bid may be subject to validation checking against Pre-Qualification data.
Optional = Required only when providing or bidding to provide the associated service.

Attachment D
Table D-2
Data Requirements for External Generators for LBMP Bidders

Data Item	Cat.	Bid Parameters	Variability	Comments
Company Name	G	--	Static Required	Parent Organization.
Generator Name/No.	G	--	Static Required	
Generator Unit Code/ID	G	--	Static Required	Unique code which identifies the generator to the ISO.
Submitted By	G	Name	May vary Required	Organization submitting bid. Multiple organizations can be authorized to submit bids with the ISO accepting the most recent. A single organization must be specified to receive invoices from the ISO.
Dependable Maximum Net Capability	P/G	MW	Static Required	Confirmed by test for units with installed capacity contracts.
Installed Capacity Contracts	P/G	MW	Variable (not within a bid) Optional	Installed Capacity contracts in effect with LSEs within the NYCA. The ISO may limit maximum and/or minimum amounts of Installed Capacity by location due to reliability Constraints.
Upper Operating Limit	C/D	MW	May change by hour for Day-Ahead Required	Maximum output of a unit that could be expected in any hour of the following operating day. The ISO must be informed of a limit change that results in less capability.

Notes:
External Generators LBMP bidders are located outside the NYCA.
Cat. = Data Categories: **G** = General; **P** = Pre-Qualification; **C** = Commitment; **B** = Balancing; **D** = Dispatch; **I** = Installed Capacity.
Static Data remains relatively constant over the lifetime of bids but can be changed.
General Data may be provided electronically or by mail, but requires a confirmation or Pre-Qualification process by the ISO.
Some data will require substantiation by a test; actual data bid may be subject to validation checking against Pre-Qualification data.
Optional = Required only when providing or bidding to provide the associated service.

Attachment D
Table D-3
Data Requirements for Generator Commitment Bids for LBMP Bidders

Data Item	Cat.	Bid Parameters	Variability	Comments
Startup Time	C/B	Hours:Minutes **or** Piecewise linear curve with Hours Off-Line as independent variable and Hours to Start as dependent variable	May be changed for any Day-Ahead Commitment Required	Length of time needed to startup an off-line Generator, synchronize it to the power grid, and stabilize at minimum.
Startup Bid Price	C/B	$ to Start **or** Piecewise linear curve with Hours Off-Line as independent variable and $ to Start as dependent variable	May be changed for any Day-Ahead Commitment Required	
Minimum Run Time	C/B	Hours:Minutes	May be changed for any Day-Ahead Commitment; may not be changed once unit is on-line Required	Duration of time that Generator must run once started before it can subsequently be decommitted. Minimum Run Time cannot be honored past the end of the Dispatch Day.
Minimum Down Time	C/B	Hours:Minutes	May be changed for any Day-Ahead Commitment Required	Duration of time that Generator must remain off-line following decommission before it can be re-started.
Maximum Number of Startups per Day	C/B	No	Static Required	

Notes:
Cat. = Data Categories: **G** = General; **P** = Pre-Qualification; **C** = Commitment; **B** = Balancing; **D** = Dispatch; **I** = Installed Capacity.
Static Data remains relatively constant over the lifetime of bids but can be changed.

Attachment D
Table D-4
Data Requirements for Generator Energy Bids

Data Item	Cat.	Bid Parameters	Variability	Comments
Minimum Generation Energy Block and Bid Price	C/B	MW and $/MW	May vary by hour	Must be provided for commitment. GT units that fully load on startup can use this form, but will set LBMP when economic.
Dispatchable Energy Bids	C/B	For Single Price Block Bids: No. of Blocks $/MW/Block **or** For Piecewise Linear Price Bids: Piecewise linear curve with MW Output as independent variable and $/MW as dependent variable	May vary by hour	Block bids would be separated by a narrow steep slope segment between each block. Resulting bid "curves" must be monotonically increasing (possessing a positive slope at all points) for SCD.
Dispatch Status	C/B	On/Off	May vary by hour	Indicates if a unit will be on or off dispatch in real time.

<u>**Notes:**</u>
Cat. = Data Categories: **G** = General; **P** = Pre-Qualification; **C** = Commitment; **B** = Balancing; **D** = Dispatch; **I** = Installed Capacity.

Attachment D
Table D-5
Data Requirements for Generator Regulation (and Frequency Control) Bids

Data Item	Cat.	Bid Parameters	Variability	Comments
Regulation Capacity Availability Bid	C/B	Table D-4 is rquired MW	May vary by hour Optional	Generator must be able to respond to AGC Base Point Signals from the ISO. The Regulation Capacity Availability Bid along with the submitted Regulation Response Rate (from Table E-1) represent the maximum response range in MW and change rate in MW/Min. LSEs engaged in Bilateral Transaction wishing to self-supply regulation must also state supplier and location.
Regulation Capacity Price Bid	C/B	$/MW	May vary by hour Optional	

Notes:
Cat. = Data Categories: **G** = General; **P** = Pre-Qualification; **C** = Commitment; **B** = Balancing; **D** = Dispatch; **I** = Installed Capacity.
Regulation Bids made for the Day-Ahead Market which are accepted are binding for the next 24 hour operating day.
Regulation not scheduled for use by the ISO may be marketed by the bidder providing no other terms or forward contracts are violated.
Unscheduled Regulation may be bid into the BME (Hour Ahead) Market, and may have a different bid price than the Day-Ahead Bid.
Optional = Required only when providing or bidding to provide the associated service.

Attachment D
Table D-6
Data Requirements for Generator Operating Reserve Bids

Data Item	Cat.	Bid Parameters	Variability	Comments
Class A 10 Minute Spinning Reserve Energy and Availability Bid	C/B/D	Table D-4 is required Also, MW Available and $/MW Availability Price Bid	May vary by hour Optional	Spinning Reserve is energy available in 10 minutes from a synchronized resource located within the NYCA that is otherwise not committed or dispatched to its Upper Operating Limit. The energy must be available for at least 30 minutes. All Generators with this bid type may be dispatched down by SCD and will be paid Lost Opportunity Cost if this occurs. A Class A unit not scheduled at maximum bid capacity in the Day-Ahead Market is limited in the amount of energy it may otherwise market in the Day-Ahead Market, such that its original Day-Ahead energy schedule **plus** its Day-Ahead Spinning Reserve schedule is still available to the ISO. Bidding into Day-Ahead Energy Market may create a forward contract for providing Class A Spinning Reserve. Energy produced in place of providing Spinning Reserve will be paid Real-Time LBMP. If a Class A unit availability bid is accepted Day-Ahead, it will be paid the Day-Ahead Spinning Reserve Availability Clearing Price. If accepted for Real-Time, it will be paid the Real-Time Spinning Reserve Availability Clearing Price. An Emergency Response Rate (ERR) must be provided.
Class B 10 Minute Spinning Reserve Availability Bid	C/B/D	MW Available and $/MW Availability Price Bid	May vary by hour Optional	Spinning Reserve is energy available in 10 minutes from a synchronized resource located within the NYCA that is otherwise not operating at its Upper Operating Limit. The energy must be available for at least 30 minutes. A Class B unit is not committed or scheduled for LBMP Energy, but can bid an availability for Spinning Reserve. If accepted Day-Ahead, it will be paid the Day-Ahead Spinning Reserve Availability Clearing Price. If accepted for Real-Time, it will be paid the Real-Time Spinning Reserve Availability Clearing Price. It will not be paid Lost Opportunity Cost. Any Energy produced will be paid Real-Time LBMP, but Class B units will not set LBMP. An Emergency Response Rate (ERR) must be provided.
Non-Synchronized 10 Minute Operating Reserve	C/B/D	MW Available and $/MW Availability Price Bid	May vary by hour Optional	MW bid must be available 10 minutes after requested. May be located External to NYCA provided the Inter-Control Area DNI Associated with this Resource can be changed in the required time. If accepted Day-Ahead, it will be paid the Day-Ahead Non-Synchronized 10 Minute Reserve Availability Clearing Price. If accepted for Real-Time, it will be paid the Real-Time Non-Synchronized 10 Minute Reserve Availability Clearing Price. Any Energy produced will be paid Real-Time LBMP.
30 Minute Operating Reserve Spinning or Non-Synchronized	C/B/D	MW Available and $/MW Availability Price Bid	May vary by hour Optional	MW bid must be available 30 minutes after requested. May be located External to NYCA provided the Inter-Control Area DNI Associated with this Resource can be changed in the required time. If accepted Day-Ahead, it will be paid the Day-Ahead 30 Minute Reserve Availability Clearing Price. If accepted for Real-Time, it will be paid the Real-Time 30 Minute Reserve Availability Clearing Price. Any Energy produced will be paid Real-Time LBMP.

Notes:
Cat. = Data Categories: **G** = General; **P** = Pre-Qualification; **C** = Commitment; **B** = Balancing; **D** = Dispatch; **I** = Installed Capacity.
Operating Reserve Bids made for the Day-Ahead Market which are accepted are binding for the next 24 hour operating day.
Operating Reserve not scheduled for use by the ISO may be marketed by the bidder providing no other terms or forward contracts are violated.
Unscheduled Operating Reserve may be bid into the BME (Hour Ahead) Market, and may have a different bid price than the Day-Ahead Bid.
Optional = Required only when providing or bidding to provide the associated service.

Attachment D
Table D-7
Data Requirements for Load Energy Bids

Data Item	Cat.	Bid Parameters	Variability	Comments
Company Name	G	--	Static	LSE, Energy Service Co. or other Transmission/Distribution Co. providing load forecast.
Point of Withdrawal (Sink) Location	G	For Internal Loads: LBMP Zone or Zone and Bus **or** For External Loads: Control Area or Control Area and Proxy Bus	Static	
Submitted By	G	Name	May Vary	Organization submitting bid.
Energy Forecast	C/B/D	MWh/hr	Variable by Hour	Total Estimate for Bid and non-Bid Load; ISO will rely on own composite load forecast as a reliability commitment to insure that all load is served. May be updated after DAM and/or Real Time to indicate adjusted load served
Energy Commit Bid	C/B/D	MW that will be committed for Day-Ahead Forward Contract	Variable by hour	Bidding is limited to the Day-Ahead Market.
Price Capped Energy Block Bids	C/B/D	No. of Blocks, MW/Block, and $/MW/Block	Variable by hour	Bidding is limited to the Day-Ahead Market.

Notes:
Cat. = Data Categories: **G** = General; **P** = Pre-Qualification; **C** = Commitment; **B** = Balancing; **D** = Dispatch; **I** = Installed Capacity.
Energy Bids made for the Day-Ahead Market which are accepted are binding for the next 24 hour operating day.

Attachment D
Table D-8
Data Requirements for Interruptible Load Spinning Reserve Bids

Data Item	Cat.	Bid Parameters	Variability	Comments
Interruptible Load for 10-Minute Spinning Reserve	C/B/D	MW Available, and $/MW Availability Price Bid	May Bid Day-Ahead	Spinning Reserve is energy available in 10 minutes from a synchronized load (by definition, all load being served is synchronized) located within the NYCA that is interruptible on demand. An interruptible load spinning reserve bid must include an energy load bid equal to or greater than the interruptible load bid (i.e., it must be consuming energy in order to provide spinning reserve in the form of a load interruption); must be reflected to an ISO bus location; must interrupt full amount within 10 minutes; and must be able to be interrupted for at least 30 minutes. An interruptible load is equivalent to Class B 10 Minute Spinning Reserve. An interruptible load that is scheduled Day-Ahead to provide Spinning Reserve will be paid the Day-Ahead Spinning Reserve Availability Clearing Price. If scheduled to provide Spinning Reserve in real-time, it will be paid the Real-Time Spinning Reserve Availability Clearing Price. An interruptible load providing Spinning Reserve must meet the requirements of the ISO including the ability to be monitored to measure interruptions.
Interruptible Load for 30-Minute Reserve	C/B/D	MW Available, and $/MW Availability Price Bid	May Bid Day-Ahead	30-Minute Reserve is energy available in 30 minutes from a synchronized load (by definition, all load being served is synchronized) located within the NYCA that is interruptible on demand. An interruptible load 30-minute reserve bid must include an energy load bid equal to or greater than the interruptible load bid (i.e., it must be consuming energy in order to provide operating reserve in the form of a load interruption); must be reflected to an ISO bus location; must interrupt full amount within 30 minutes. An interruptible load that is scheduled Day-Ahead to provide 30-minute Reserve will be paid the Day-Ahead 30-minute Reserve Availability Clearing Price. If scheduled to provide 30-minute Reserve in real-time, it will be paid the Real-Time 30-minute Reserve Availability Clearing Price. An interruptible load providing 30-minuteReserve must meet the requirements of the ISO including the ability to be monitored to measure interruptions.

Notes:
Cat. = Data Categories: **G** = General; **P** = Pre-Qualification; **C** = Commitment; **B** = Balancing; **D** = Dispatch; **I** = Installed Capacity.
Operating Reserve Bids made for the Day-Ahead Market which are accepted are binding for the next 24 hour operating day.
Operating Reserve not scheduled for use by the ISO may be marketed by the bidder providing no other terms or forward contracts are violated.
Unscheduled Operating Reserve may be bid into the BME (Hour Ahead) Market, and may have a different bid cost than the Day-Ahead Bid.