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 Load Serving Entities ("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.

2.8 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.~~**2.9a Back-up Operation Procedures:** The ISO shall develop Back-up Operation procedures that will carry out the intent and purposes of this Tariff to the extent practical, taking into consideration circumstances under which the normal communications or computer systems of the ISO are not fully functional. Such procedures shall include testing requirements and training for the ISO staff, Transmission Owner staff, and Market Participants. If communication or computer systems malfunctions result in the ISO's inability to operate the NYCA in accordance with the ISO's 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.

2.9b 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.

2.9c Billing and Settlement: In the event that Back-up Operation is implemented, the billing and Settlement Procedures contained in this Tariff shall apply only to the extent they can be implemented by 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 Transmission Customers. The ISO shall be under no obligation to comply with the billing procedure time limits specified in Section 7. Neither the ISO nor the Transmission Owners shall be liable, under any circumstances, for any economic losses suffered by any Transmission Customer, Market Participant, or third party, resulting from the implementation by the ISO of Back-up Operation or 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.

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 ~~n~~Non-Firm and Firm Transmission Service as needed for the Dispatch Hour for which the SCUC applies.

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 in the Day-Ahead Market for Energy ~~over a defined time period~~ is less than the amount of Congestion Rent revenue in the Day-Ahead Market for Energy that the ISO is obligated under the ISO OATT to pay out to the Primary Holders of TCCs.

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 ~~c~~Capacity to maintain operating reserves in accordance with Good Utility Practice.

2.33 Curtailment or Curtail

A reduction in Firm or ~~n~~Non-Firm Transmission Service in response to a transmission ~~c~~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 preceeding 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 ~~b~~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

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

2.51 Existing Transmission Capacity for Native Load ("ETCNL")

Transmission ~~c~~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 ~~c~~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

A Bilateral Transaction or ~~P~~purchases from the LBMP Market where the Energy is delivered to an NYCA ~~i~~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 the ISO OATT ~~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 [NOT USED] ~~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 ~~c~~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.

2.79 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.

2.80a Investor-Owned Transmission Owners

At the present time these include: Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation.

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 ~~l~~**L**oad in the NYCA.

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.

2.107a Native Load Customers

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

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.

2.113 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 ~~g~~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.

2.122a NYPA Transmission Adjustment Charge ("NTAC"):

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

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.

2.128a Operating Committee

A standing committee of the ISO created pursuant to the ISO Agreement, which coordinates operations, develops procedures, evaluates proposed system expansions and acts as a liaison to the NYSRC.

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).

2.143 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.

2.144 Power 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 Transmission Customer that has purchased the TCC in the Centralized TCC Auction, and that has not resold it in that same Auction; (2) a Transmission Customer that has purchased the TCC in a Direct Sale with another Transmission Customer; (3) the Primary Owner who has retained the TCC ~~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 Transmission Customer. The ISO Day-Ahead settles Congestion Rents pursuant to Attachments ~~J~~M and N to the ISO OATT with the Primary Holder of each TCC.

2.148 Primary Owner

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

2.159a Residual Adjustment

The ISO's collections from Loads and Transmission Customers, less its payment to generating facilities, less Congestion Rents and Excess Congestion Rents, and Primary Holders of TCCs as defined in Schedule 1.

2.160 Residual TCCs

TCCs converted from ~~RTC~~ Residual Transmission Capacity (as defined in the ISO OATT), 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 expires and the associated ~~c~~Capacity is released to the ISO for sale and ~~are~~ is not allocated but ~~are~~ is 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).

2.160a Residual Transmission Capacity ("RTC"): The transmission capacity determined by the ISO before, during and after the Centralized TCC Auction which is conceptually equal to the following:

RTC = TTC - TRM - CBM - GTR - GTCC - ETCNL

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

TTC is the Total Transfer Capability that can only be determined after the RTC is known.

GTR is the transmission capacity associated with Grandfathered Rights.

GTCC is the transmission capacity associated with Grandfathered TCCs.

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

TRM is the Transmission Reliability Margin.

CBM is the Capacity Benefit Margin.

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 [NOT USED] ~~Second Contingency Design and Operation~~

~~The planning, designing 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.~~

2.163a Secondary Holders

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

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.

2.174 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 ~~t~~Transmission ~~s~~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 ~~g~~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 in the Day-Ahead Market for Energy associated with a single MW of transmission between a specified POI and POW. TCCs are financial instruments that enable Energy buyers and sellers to hedge fluctuations in the price of transmission.

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.

2.186a Transmission Facility Agreement

The agreements listed in Attachment L, Table 2 of the ISO OATT governing the use of specific or designated transmission facilities charges all, or a portion, of the costs to install, own, operate, or maintain said transmission facilities, to the customer under the agreement. These agreements may or may not have provisions to provide Transmission Service utilizing said transmission facilities.

2.186b Transmission Fund ("T-fund")

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

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.

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.

In order to ensure that the Day-Ahead commitment will be able to serve the ISO's Day-Ahead forecast of Load, the ISO shall be permitted to limit the amount of Energy offered at any given time by a Generator into the Day-Ahead Market to the amount of Energy it reasonably believes that Generator is capable of producing at that point in time. 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 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 ~~i~~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~~Minimum Generation and Start-Up Bid costs of meeting forecasted peak Load plus Ancillary Services consistent with the Reliability Rules; (5) ~~I~~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).

If the ISO is not able to post the Day-Ahead Schedule by 11 a.m. as specified herein due to technical difficulties such as inability to solve unit commitment, or other issues related to finalizing the Day-Ahead Schedule, the ISO shall have reasonable flexibility to delay the portion of the Day-Ahead Schedule if necessary to ensure system reliability. In such event, all timely Bids received for inclusion in the Day-Ahead schedule will remain binding.

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 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 ~~c~~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

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 Market 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 Market Settlements for injections by resources supplying Regulation service follow the rules which are described in Rate Schedule 3.)

For the purposes of this section, the scheduled output of each of the following Generators in each SCD interval shall retroactively be set equal to its actual output in that SCD interval:

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

(ii) Existing topping turbine Generators and extraction turbine Generators producing electric Energy resulting from the supply of steam to the district steam system located in New York City (LBMP Zone J) and/or topping or extraction turbine Generators utilized in replacing or repowering existing steam supplies from such units (in accordance with good engineering and economic design) that cannot follow schedules, up to a maximum total of 365 MW of such units; and

(iii) Existing intermittent (i.e., non-schedulable) renewable resource Generators within the NYCA, plus up to an additional 50 MW of such Generators;

This procedure shall not apply to a Generator at times when it has been scheduled to provide Regulation or Operating Reserves.

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.

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~~ would have received for providing these Ancillary Services prior to any reductions based on a failure to provide these 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

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

(e) It must ensure the continued compatibility of its local ~~e~~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 ~~t~~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 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 ~~i~~Internal and ~~e~~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 ~~e~~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. Generator Availability ~~S~~standards in effect under the NYPP will remain in effect unless and until the ISO implements new Generator Availability ~~S~~standards.

Generator Availability ~~S~~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.

Prior to each Capability Period, once the LSE has arranged Installed Capacity supply and has entered into contracts for such supply, it must demonstrate to the ISO that it has met its Installed Capacity requirements.

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 following quantity, which will be calculated for each Load, summed over all Loads: 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 within that Transmission District while it was served by that LSE 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.

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 ~~i~~Interconnection assistance benefits from neighboring Control 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.

In order for such a purchase of additional Installed Capacity to count towards an LSE's Installed Capacity requirement, the purchase must have been consummated, and the ISO must have been notified of that purchase, by the end of the month following the month in which final Installed Capacity requirements for each LSE are announced by the ISO. At that time, the ISO will calculate installed capacity deficiencies as follows:

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

LSE_{DEF} = <GREATER OF> 0MW <OR> $IC_{REQ} - LSE_{1C}$

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

LSE_{1C} = 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 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 had no outstanding amounts due, the ISO may pay to the Customer an amount equal to the overpayment. The ISO's invoices to Transmission Customers will be submitted only by electronic means via the ISO's Bid/Post System.

B. Payment by the Customer

Invoices shall be paid by the Customer ~~within twenty (20) days of receipt~~ by the first Business Day after the 15th day of the month that the invoice is rendered by the ISO. All payments shall be made by wire transfer in immediately available funds payable to the ISO as trustee of the ISO Clearing Account.

C. Payment by the ISO

The ISO shall pay all net monies owed to a Customer ~~within twenty (20) days of the date of the invoice~~ by the first Business Day after the 19th day of the month that the invoice is rendered by the ISO. 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

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 ~~t~~Transactions under this Tariff, the Customer agrees that its Service Agreement and ~~t~~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.

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. A Customer taking or providing service under the Tariff shall provide the ISO, upon application for service, with a list identifying its parent company as well as any Affiliate. The Customer shall notify the ISO within 30 days of the effective date of any change to the original list. Any Customer shall notify the ISO within 30 days of the effective date of any change to the original list. Any Customer shall respond within 10 days to a request by the ISO to update the list of Affiliates and/or parent company. 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 in 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

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 the 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 ~~t~~Transmission ~~s~~Service

(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 ~~p~~Power ~~f~~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~~ from FERC Form 1, Account #315, 324, 334, or 345.

(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 ~~l~~Lost ~~o~~Opportunity Cost 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).

(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 ~~r~~Reactive ~~p~~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 ~~c~~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-

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 ~~c~~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 ~~c~~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 the 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

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~~ thirty (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 thorough 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; MCP is the Market Clearing Price ($/MW) which applies to the SCD interval for which Regulation Service in the Real-Time Market, or the Day-Ahead Market if no 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.

Regulation charges will not be assessed in association with the output of the following Generators:

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

(ii) Existing topping turbine Generators and extraction turbine Generators producing electric Energy resulting from the supply of steam to the district steam system located in New York City (LBMP Zone J) and/or topping or extraction turbine Generators utilized in replacing or repowering existing steam supplies from such units (in accordance with good engineering and economic design) that cannot follow schedules, up to a maximum total of 365 MW of such units; and

(iii) Existing intermittent (i.e., non-schedulable) renewable resource Generators within the NYCA, plus up to an additional 50 MW of such Generators;

The above exemptions from Regulation charges associated with the output of a Generator in one of the above categories shall not apply when that Generator has been scheduled to provide Regulation or Operating Reserves, or when that Generator sells Energy through any mechanism other than an existing PURPA contract (if the reason why that Generator qualifies for exemption from Regulation charges is because it sells Energy under an existing PURPA contract). In such hours, Regulation charges (if any) shall be assessed to the Supplier whose Generator is included in one of the above categories. These charges shall be calculated under § 4.1 of this Rate Schedule, if that Generator supplies Regulation, and under § 4.2 of this Rate Schedule, if that Generator does not supply Regulation.

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 ~~l~~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 ~~s~~Suppliers of Spinning Reserve must be located within the NYCA and must be under ISO Operational ~~c~~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 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 scheduled 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 ~~e~~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

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 ~~P~~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

A Class A Supplier~~s~~ of Spinning Reserve ~~whose Class A output~~ which produces less Energy in the Real-Time dispatch ~~has been reduced for the purpose of creating~~ than it would have been economic for it to produce because it has been selected (in the Day-Ahead or Real-Time Markets) to provide Spinning Reserve will be paid for Lost Opportunity Costs. The Lost Opportunity Cost ~~p~~Payment ("LOCP") that each such Supplier receives in each SCD interval shall be computed by multiplying the following: (i) the Marginal Lost Opportunity Cost ("MLOC") in ~~each hour by~~ that interval, in \$/MW; (ii) the number of MW of Spinning Reserve supplied by that Supplier in that ~~hour.~~interval; and (iii) the length of the SCD interval, in hours. MLOC in each SCD interval shall be calculated as follows:

$$MLOC = \max_{i \varepsilon s} (P_i - B_i)$$

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 in that interval; and

S_i = Set of Generators ~~backed down~~ whose Energy output in that interval has been reduced below the level that otherwise would have been economic, due to the fact that they have been selected (either Day-Ahead or Real-Time) 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.

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 Market Settlement.)

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 ~~c~~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 Suppliers 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~~ **average** ratio of the amount of Energy supplied to the amount of Energy scheduled,

set by a second SCD execution in which Generator ramp rate ~~c~~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 ~~r~~Real-~~t~~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,

$$\gamma = \sum \gamma$$

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

$$\gamma = \sum \gamma$$

is the Congestion Component of the LBMP for zone j;

n = number of ~~l~~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.

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 ~~t~~Transmission ~~s~~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 ~~e~~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 $/M~~w~~Wh.

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 such an advance

notification to the ISO, an External Supplier will have the additional option of being modeled at a specific External LBMP bus (rather than an External Proxy Generator Bus) and being able to submit a bid curve. Otherwise, an External Supplier with Incremental or

Decremental Bids at an External Proxy Generator Bus will be modeled as a single point price curve at that bus. An LBMP bus is a specific bus at which a Generator Shift Factor has been calculated, and for which LBMP will be calculated.

(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 ~~n~~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)~~(8) 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)~~(9) 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 **taking service under the ISO OATT** 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 ~~c~~Customers requesting Firm Transmission Service to the extent that is physically feasible.

(iv) The ISO shall not schedule ~~n~~Non-Firm Transmission Service Day-Ahead for a Transaction if Congestion Rents associated with that Transaction are positive, nor will the ISO schedule ~~n~~Non-Firm Transmission Service in the BME if Congestion Rents associated with that Transaction are expected to be positive. All schedules for ~~n~~Non-Firm Point-to-Point Transmission Service are advisory only and are subject to Reduction if ~~R~~real-~~T~~time Congestion Rents associated with those Transactions become positive. Transmission Customers receiving ~~n~~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~~ Transmission Customer, if it takes service under this Tariff, shall pay the Day-Ahead LBMP price, at the Point of Receipt for the Transaction, for the replacement amount of Energy (in MWh) purchased in the LBMP Market. If the Transmission Customer does not take service under this Tariff, it shall pay the greater of 150 percent of the Day-Ahead LBMP at the Point of Receipt for the Transaction or $100/MWh for the replacement amount of energy, as specified in the OATT. These procedures shall apply regardless of whether the Generator designated to supply Energy in association with the Transaction was located inside or outside the NYCA.

If the Transaction was scheduled following the Day-Ahead Market, or the schedule for the Transaction was revised following the Day-Ahead Market, then the ISO 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. If the Transmission Customer does not take service under this Tariff, it shall pay the greater of 150 percent of the Real-Time LBMP at the Point of Injection for the Transaction or $100/MWh for the replacement amount of Energy, as specified in the OATT. (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.) These procedures shall apply regardless of whether the Generator designated to supply Energy in association with the Transaction was located inside or outside the NYCA.

If the 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-~~f~~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 ~~n~~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 ~~n~~Non-~~f~~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 ~~f~~Firm ~~t~~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 amount of Transmission Service scheduled hour-ahead in the BME for transactions supplied by one of the following Generators shall retroactively be set equal to that Generator's actual output in each SCD interval:

(i) Generators providing Energy under existing contracts (including PURPA contracts) in which the power purchaser does not control the operation of the supply source but would be responsible for penalties for being off-schedule;

(ii) Existing topping turbine Generators and extraction turbine Generators producing electric Energy resulting from the supply of steam to the district steam system located in New York City (LBMP Zone J) and/or topping or extraction turbine Generators utilized in replacing or repowering existing steam supplies from such units (in accordance with good engineering and economic design) that cannot follow schedules, up to a maximum total of 365 MW of such units; and

(iii) Existing intermittent (i.e., non-schedulable) renewable resource Generators within the NYCA, plus up to an additional 50 MW of such Generators;

This procedure shall not apply at times when the Generator supplying that transaction has been scheduled to provide Regulation or Operating Reserves.

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 ~~c~~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 ~~m~~Multiple-~~r~~Round ~~a~~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 ~~t~~Transfer ~~c~~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

~~t~~Transmission ~~c~~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 ~~c~~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~~ their 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 and ETCNL 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 or ETCNL. 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.

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~~ twenty-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), ~~c~~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 ~~t~~Transmission ~~c~~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

Primary Owners of Residual TCCs shall inform the ISO of all sales of those TCCs, including the identify 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~~Transitional 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. Auctions for TCCs

8.1 Transmission Capacity Sold in Centralized Auctions for TCCs

In the Auction the following transmission ~~c~~Capacity shall be available for purchase in the form of TCCs: (1) all of the transmission ~~c~~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 ~~c~~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 ~~c~~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 ~~t~~Transmission ~~s~~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~~ one (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 ~~c~~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 ~~c~~Capacity sold in the Auction as the TCCs with either a 6 month or 1 year duration. Subject to this constraint, the final decision concerning the percentage of the transmission ~~c~~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 ~~c~~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 the 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 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 On-~~p~~Peak and ~~o~~Off-~~p~~Peak TCCs. (For purposes of this Attachment, the On-~~p~~Peak period will include the hours 7 a.m. to 11 p.m. Prevailing Eastern Time Monday through Friday. The remaining hours in each week will be included in the ~~o~~Off-~~p~~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 ~~s~~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 ~~c~~Capacity required to be aside to support TCCs with a duration of six months or one year will not apply. All available transmission ~~c~~Capacity will be sold in these Auctions, including transmission ~~c~~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 ~~c~~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 ~~c~~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 On-~~p~~Peak and ~~o~~Off-~~p~~Peak periods, or TCCs valid during the 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 ~~t~~Transfer ~~c~~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 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 ~~c~~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 ~~c~~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 ~~c~~Capacity that can be used to support TCCs purchased in this Auction shall include the portion of the transmission ~~c~~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 ~~c~~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 ~~c~~Capacity used to support these TCCs, as well as any other transmission ~~c~~Capacity not required to support already-outstanding TCCs, will be available to support TCCs purchased in the Reconfiguration Auction.

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 State 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 or 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 ~~t~~Transfer ~~c~~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 Optim~~um~~al 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 Optim~~um~~al Power Flows without direct ISO involvement. The ISO will continue to verify that the Optim~~um~~al 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 Optim~~um~~al Power Flow results calculated by the auctioneer are inaccurate; (2) the Optim~~um~~al Power Flow is not calculated in accordance with the correct procedure; or (3) in the ISO's objective opinion, the auctioneer is

TCCs for sale that are valid in sub-periods (e.g., On-~~p~~Peak or ~~o~~Off-~~p~~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 On-~~p~~Peak and ~~o~~Off-~~p~~Peak TCCs, the procedure used to select winning Bids in ~~a~~ an On-~~p~~Peak Auction will not depend on winning Bids selected in an ~~o~~Off-~~p~~Peak Auction; nor shall the procedure used to select winning Bids in an ~~o~~Off-~~p~~Peak Auction depend on winning Bids selected in ~~a~~ an On-~~p~~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 ~~c~~Capacity available in Stage 1 among each of the rounds

(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 On-~~p~~Peak and ~~o~~Off-~~p~~Peak periods, if On-~~p~~Peak and ~~o~~Off-~~p~~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 ~~c~~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 ~~c~~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

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 TCC 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~~Owners 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 IMWM (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:

$$IMWM(i) = \sum_{j=1}^{TCC} \sum_{k=1}^{10} \left[\left(\frac{mwmile_{ik}}{\sum_{m=1}^{TrO} mwmile_{mk}} \right) \cdot \left(\frac{CC_{jk}}{\sum_{n=1}^{TCC} \sum_{p=1}^{10} CC_{np}} \right) \right]$$

Where,

i	=	Transmission Owner for which the coefficent is calculated.
j,n	=	Index variables for TCCs.
k,p	=	Index variables for Interfaces.
m	=	An index variable for Transmission Owners.
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 Owner *i*.
$mwmile_{mk}$	=	Total of the megawatts times miles of circuits in zones associated with Interface *k* for Transmission Owner *m.*
CC_{jk}	=	Congestion associated with a TCC *j* across Interface *k*.
~~CC_{jl}~~	~~=~~	~~Congestion associated with a TCC *j* across Interface l.~~
CC_{np}	=	Congestion associated with a TCC *n* across Interface *p.*

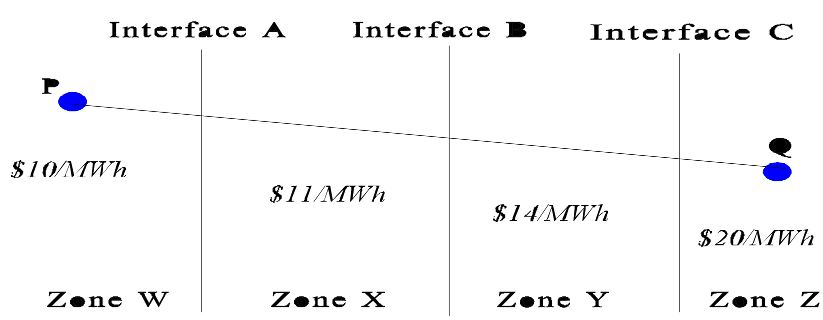
The first term of the above equation shall be referred to as the MW-mile component and the second term of the above equation shall be referred to as the Congestion Component. When calculating the IMWM(i) coefficient for distribution of revenues from the Centralized TCC Auction, the ISO shall determine 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 If a Transmission Owner releases a Residual TCC or a MW of ETCNL for sale in a round of the Centralized Auction, and the market-clearing price for that TCC in that round is negative, the value of that TCC will not be included in the determination of payments to the Transmission Owners for Residual TCCs or ETCNL released into the Centralized TCC Auction. If the market-clearing price is negative for ETCNL and Residual TCCs, the value will be set to zero in the calculation of ETCNL and Residual TCC allocation. If the total value of the auction revenues available for payment to the Transmission Owners for Residual TCCs or ETCNL released into the Centralized TCC Auction is insufficient to fund payments at market-clearing prices, the total payments to each Transmission Owner will be reduced proportionately. This proportionate reduction would include a reduction in payments reflecting a proportionate reduction in the Auction value of Residual TCCs sold in a Direct Sale.

If the Congestion associated with a TCC across an Interface (in CC_{jk} Section 3.4) employed in the MW-Mile Methodology to allocate Excess Congestion Rents and Congestion Rent Shortfalls is negative, then the Congestion across that interface shall be set equal to zero for the purpose of applying the MW-Mile Methodology to the allocation of Excess Congestion Rents among the Transmission Owners.

~~3.5~~ 3.6 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 $/M~~w~~Wh: 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 of the Day-Ahead LBMP ($/MWh) at the Point of Withdrawal ("POW")

CC_{POI} = Congestion Component of the Day-Ahead LBMP ($/MWh) at the Point of Injection ("POI")

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

(See Attachment ~~J~~B to the ISO ~~OATT~~Services Tariff 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 Day-Ahead Congestion Components at the POWs minus the Congestion Components at the POIs multiplied by the Energy associated with the POWs ~~and POIs~~ in the Day-Ahead LBMP Markets minus the Day-Ahead Congestion Component at each POI multiplied by the Energy associated with the POI in the Day-Ahead LBMP Market; (ii) the Day-Ahead 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~~Attachment N of the ISO OATT.

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~~ N of the ISO OATT for creditor collection through their respective TSC or ~~NTAC~~NYPA Transmission Adjustment Charge ("NTAC").

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 ~~s~~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~~Service, 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 when 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~~constrained 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
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 ~~g~~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 ~~b~~Bid. Multiple organization can be authorized to submit ~~b~~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 ~~c~~Capacity contracts, or historical production data.
Power Factor	P/G	MW/MVA	Static Optional	Generator's tested Power Factor for producing ~~r~~Reactive ~~p~~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 ~~b~~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 ~~b~~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 ~~g~~G enerator to the ISO.
Submitted By	G	Name	May vary Required	Organization submitting ~~b~~Bid. Multiple organizations can be authorized to submit ~~b~~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 ~~b~~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 ~~b~~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 ~~b~~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-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~~ **required** 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 ~~s~~**S**elf-~~s~~**S**upply regulation must also state ~~s~~**S**upplier 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 ~~b~~**B**id 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 E~~e~~nergy 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 ~~b~~**B**id ~~c~~**C**apacity in the Day-Ahead Market is limited in the amount of E~~e~~nergy 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 E~~e~~nergy available in 10 minutes from a synchronized resource located within the NYCA that is otherwise not operating at its Upper Operating Limit. The E~~e~~nergy must be available for at least 30 minutes. A Class B unit is not committed or scheduled for LBMP Energy, but can bid an ~~a~~**A**vailability 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 ~~b~~**B**id 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 ~~b~~**B**id 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 ~~b~~**B**id 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 ~~l~~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 ~~b~~**B**id.
Energy Forecast	C/B/D	MWh/hr	Variable by Hour	Total Estimate for Bid and non-Bid Load; ISO will rely on own composite ~~l~~Load forecast as a reliability commitment to insure that all ~~l~~Load is served. May be updated after DAM and/or Real Time to indicate adjusted ~~l~~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 ~~e~~Energy available in 10 minutes from a synchronized ~~l~~Load (by definition, all ~~l~~Load being served is synchronized) located within the NYCA that is interruptible on demand. An interruptible ~~l~~Load spinning reserve ~~b~~Bid must include an E~~e~~nergy ~~l~~Load ~~b~~Bid equal to or greater than the interruptible ~~l~~Load ~~b~~Bid (i.e., it must be consuming energy in order to provide spinning reserve in the form of a ~~l~~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 ~~l~~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 ~~l~~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 ~~l~~Load (by definition, all ~~l~~Load being served is synchronized) located within the NYCA that is interruptible on demand. An interruptible load 30-minute reserve ~~b~~Bid must include an ~~e~~Energy ~~l~~Load ~~b~~Bid equal to or greater than the interruptible ~~l~~Load ~~b~~Bid (i.e., it must be consuming energy in order to provide operating reserve in the form of a ~~l~~Load interruption); must be reflected to an ISO bus location; must interrupt full amount within 30 minutes. An interruptible ~~l~~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 ~~l~~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 ~~b~~Bid cost than the Day-Ahead Bid.