# Attachment II

## 1.18 Definitions - R

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

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

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

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

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

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

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

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

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

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

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

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

**Reconfiguration Auction:** The monthly auction administered by the ISO in which Transmission Customers may purchase and sell one-month TCCs.

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

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

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

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

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

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

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

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

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

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

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

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

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

GTR is the transmission capacity associated with Grandfathered Rights.

GTCC is the transmission capacity associated with Grandfathered TCCs.

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

TRM is the Transmission Reliability Margin.

CBM is the Capacity Benefit Margin.

**Retired:** As defined in the ISO Services Tariff.

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

**RMR Avoidable Costs:** The (a) fixed costs of an Initiating Generator that would be avoided if it were to exit the ISO-Administered Markets in the manner specified in its Generator Deactivation Notice, (b) the fixed costs of a Generator already in a Mothball Outage, an ICAP Ineligible Forced Outage, or that has been mothballed since before May 1, 2015 that would be incurred if it were to re-enter the ISO-Administered Markets pursuant to an RMR Agreement that would be avoided if it remained in such state, or (c) the costs necessary for a new Generator proposed as a Gap Solution to enter service. RMR Avoidable Costs include mandatory capital expenditures, fixed operating and maintenance costs, and forgone opportunity costs, determined by the ISO in accordance with Section 31.2.11.8 of Attachment Y, as modified by the

Commission. RMR Avoidable Costs do not include variable costs or any other type of cost that are included in the Generator's Energy or Ancillary Services reference levels, or that are ordinarily included in Energy or Ancillary Services reference levels.

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

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

## 6.10 Schedule 10 - Rate Mechanism for the Recovery of the Reliability Facilities Charge ("RFC")

### 6.10.1 Applicability.

This rate mechanism establishes the Reliability Facilities Charge ("RFC") for the recovery of costs related to: (i) a regulated backstop transmission solution identified by the ISO pursuant to Section 31.2.4.3.1 of Attachment Y of the ISO OATT and the NYISO/TO Reliability Agreement, (ii) an alternative regulated transmission solution provided that the ISO has selected such project pursuant to Section 31.2.6.5.2 of Attachment Y of the ISO OATT as the more efficient or cost effective solution to the identified Reliability Need, or (iii) a regulated transmission Gap Solution proposed by a Responsible Transmission Owner or an alternative regulated transmission Gap Solution proposed by an Other Developer or Transmission Owner that has been identified pursuant to Section 31.2.11.9 of Attachment Y of the ISO OATT as a solution to be implemented to address an identified Reliability Need. This rate mechanism shall not apply to the recovery of costs related to: (i) projects undertaken by Transmission Owners pursuant to Local Transmission Owner Planning Processes pursuant to Section 31.1.3 and Section 31.2.1 of Attachment Y of the ISO OATT, (ii) a Generator operating under an RMR Agreement as a Gap Solution to an identified Reliability Need, or (iii) a non-transmission Gap Solution identified pursuant to Section 31.2.11.9 of Attachment Y of the ISO OATT as a solution to be implemented to address an identified Reliability Need. The RFC shall be comprised of the revenue requirements related to: (i) each regulated reliability transmission project filed with FERC by a Transmission Owner pursuant to the provisions of this Attachment; (ii) any costs incurred by NYPA and filed with FERC by the ISO pursuant to the provisions of this Attachment; and (iii) any FERC approved costs incurred by an Other Developer under Section 6.10.5 and filed with FERC by the ISO or Other Developer pursuant to the provisions of this

Attachment. Any costs incurred by LIPA and allocable to other Transmission Districts will be collected under a separate LIPA RFC as set forth in Section 6.10.4.3 and filed with FERC by the ISO pursuant to the provisions of Section 6.10.4.3. This RFC will provide for full recovery of all reasonably incurred costs related to the preparation of proposals for, and the development, construction, operation and maintenance of any regulated reliability transmission project undertaken pursuant to Attachment Y of this tariff, including all reasonable costs related to such a project that is halted in accordance with the provisions of the ISO's tariff and the NYISO/TO Reliability Agreement. Subject to regulatory acceptance, the RFC shall include a reasonable return on investment and any applicable incentives. The RFC established under this Attachment shall be separate from the Transmission Service Charge ("TSC") and the NYPA Transmission Adjustment Charge ("NTAC") determined in accordance with Attachment H of the ISO OATT. With respect to the recovery of costs incurred by LIPA and NYPA, the provisions of Sections 6.10.1, and 6.10.2 through 6.10.3.4 of this Attachment shall not apply to LIPA or NYPA, except as provided for in Sections 6.10.4.3 and 6.10.4.4 of this Attachment. The recovery of costs related to development, construction, operation and maintenance of a regulated reliability transmission project undertaken by LIPA or NYPA shall be pursuant to the provisions of Sections 6.10.4.3 and 6.10.4.4 of this Attachment**.** The recovery of costs related to development, construction, operation and maintenance of an alternative regulated transmission project proposed by an Other Developer shall be pursuant to the provisions of Section 6.10.5 of this Attachment.

### 6.10.2 Recovery of Transmission Owner's Costs Related to Regulated Reliability Transmission Solutions.

Each Transmission Owner shall have on file at FERC the rate treatment that will be used to derive and determine the revenue requirement to be included in the RFC, and for the LIPA

RFC as applicable, for regulated transmission projects undertaken pursuant to a determination by the ISO that a regulated solution is needed to address Reliability Needs identified by the ISO in its reliability planning process in accordance with Section 31.2.8 of Attachment Y of the ISO OATT or in its Gap Solution process in accordance with Section 31.2.11 of Attachment Y of the ISO OATT. The filing will provide for the recovery of the full revenue requirement for a regulated reliability transmission project consistent with FERC regulations including but not limited to any incentives for the construction of transmission projects provided for in Section 219 of the Federal Power Act and the FERC regulations implementing that section. Pursuant to a determination by the ISO that a regulated transmission solution is needed to address Reliability Needs identified by the ISO in its reliability planning process in accordance with Section 31.2.8 of Attachment Y of the ISO OATT, (i) the Responsible Transmission Owner(s) proceeding with a regulated transmission backstop solution or (ii) a Transmission Owner proceeding with an alternative regulated transmission solution that the ISO has selected as the more efficient or cost effective solution, will proceed with the approval process for all necessary federal, state and local authorizations for the requested project to which this RFC applies. Pursuant to a determination in Section 31.2.11.9 of Attachment Y of the ISO OATT identifying a transmission solution as a Gap Solution to be implemented to address an identified Reliability Need, the Responsible Transmission Owner or Transmission Owner that proposed the transmission solution will proceed with the approval process for all necessary federal, state and local authorizations for the requested project to which the RFC applies.

6.10.2.1 Upon receipt of all necessary federal, state, and local authorizations, including FERC acceptance of the rate treatment, the Transmission Owner(s) shall commence construction of the transmission project, including a transmission

project identified pursuant to Section 31.2.11.9 of Attachment Y of the ISO OATT as a Gap Solution, in order to meet the Reliability Need by the need date.

6.10.2.2 Upon completion of the project, the Transmission Owner(s) or the ISO as applicable, will make an informational filing with FERC to provide the final transmission project cost and resulting revenue requirement to be recovered pursuant to this Attachment. The final project cost and resulting revenue requirement will be reduced by any amounts that, pursuant to Section 25.7.12.3.3 of Attachment S to the ISO OATT, have been previously committed by or collected from Developers for the installation of System Deliverability Upgrades required for the interconnection of generation or merchant transmission projects. The resulting revenue requirement will become effective and recovery of project costs pursuant to this Attachment will commence upon the making of the information filing with FERC, and shall not require and shall not be dependent upon a re-opening or review of the Transmission Owner(s)' revenue requirements for the TSCs and NTAC set forth in Attachment H of the ISO OATT. This Section 6.10.2.2 also applies to the recovery of all reasonably incurred costs related to either (i) a regulated backstop transmission project or (ii) an alternative regulated transmission project that the ISO has selected as the more efficient or cost effective solution and that is later halted, including but not limited to reasonable and necessary expenses incurred to implement an orderly termination of the project, in accordance with the provisions of the ISO OATT and the NYISO/TO Reliability Agreement. Following the information filing, the ISO will bill the RFC or LIPA RFC, as applicable.

6.10.2.3 The Transmission Owners may propose a non-transmission solution subject to state jurisdiction to address a Reliability Need included in the Comprehensive Reliability Plan, provided that the appropriate state agency(ies) has established procedures to ensure full and prompt recovery of all reasonably incurred costs related to a project, comparable to those set forth in this tariff for cost recovery for regulated reliability transmission projects.

**6.10.3 RFC Revenue Requirement Recovery.**

The RFC is to be billed by the ISO and paid by the LSEs located in the Load Zones and/or Subzones to which the cost of the transmission facilities have been allocated in accordance with Attachment Y of the ISO OATT. All LSEs in the Load Zones and/or Subzones to which costs have been allocated, including Transmission Owners, competitive LSEs and municipal systems, will be billed by the ISO.

6.10.3.1 The revenue requirement filed pursuant to Section 6.10.2.2 will be the basis for the RFC Rate ($/MWh) for the Billing Period, and shall be applied by the ISO to each LSE based on its Actual Energy Withdrawals as set forth in Section 6.10.3.4.

6.10.3.2 To the extent that incremental transmission rights owned by the Transmission Owner sponsoring the project are created as a result of a transmission project implemented in accordance with Attachment Y of the ISO OATT, those incremental transmission rights that can be sold will be auctioned or otherwise sold by the ISO. The ISO will disburse the associated revenues to the Transmission Owner(s). The associated revenues will be used in the calculation of the RFC as set forth in Section 6.10.3.4. The incremental transmission rights

will continue to be sold for the depreciable life of the project, and the revenues offset discussed above will commence upon the first payment of revenues related to a sale of incremental transmission rights on or after the RFC is implemented for a specific project. These incremental revenues shall not require and shall not be dependent upon any reopening or any review of the Transmission Owner(s) TSCs or NTAC under Attachment H of the ISO OATT.

6.10.3.3 The ISO will collect the appropriate RFC revenues each Billing Period and remit those revenues to the appropriate Transmission Owner(s) in accordance with the ISO's billing and settlement procedures pursuant to Section 2.7.2.5 of the ISO OATT.

6.10.3.4 The Billing Units for the RFC Rate for the Billing Period shall be based on the Actual Energy Withdrawals available for the current Billing Period for those Load Zones and/or Subzones determined to be allocated the costs of the project in accordance with Attachment Y of the ISO OATT.

**Step 1: Calculate the $ assigned to each Load Zone or Subzone (as applicable)**

$$RFC_{z,B} = \sum_{p \in P} \left( \left( AnnualRR_{p,B} - IncrementalTransmissionRightsRevenue_{p,B} \right) * \left( ZonalCostAllocation\%_{P} \right) \right)$$

**Step 2: Calculate a per-MWh Rate for each Load Zone or Subzone (as applicable)**

$$RFCRate_{z,B} = RFC_{z,B} / MWh_{z,B}$$

**Step 3: Calculate charge for each Billing Period for each LSE in each Load Zone or Subzone (as applicable)**

$$Charge_{B,1,z} = RFCRate_{z,B} * MWh_{1,z,B}$$

**Step 4: Calculate charge for each Billing Period for each LSE across all Load Zones or Subzones (as applicable)**

$$Charge_{B,1} = \sum_{z \in Z} (Charge_{B,1,z})$$

Where,

$P$ = set of Projects.

$Z$ = set of ISO Load Zones or Subzones, as applicable.

$B$ = the relevant Billing Period.

$MWh_{z,B}$ = Actual Energy Withdrawals in Load Zone or Subzone, as applicable, z aggregated across all hours in Billing Period B.

$MWh\ l, z, B_{1,z,B}$ = Actual Energy Withdrawals for LSE l in Load Zone or Subzone, as applicable, z aggregated across all hours in Billing Period B.

$AnnualRR_{p,B}$ = the pro rata share of the annual Revenue Requirement for each Project as discussed in Section 6.10.2.2 above allocated for Billing Period B.

$IncrementalTransmissionRightsRevenue_{p,B}$ = the pro rata share of the Incremental Transmission Rights Revenue for each Project as discussed in Section 6.10.3.2 above allocated for Billing Period B.

### 6.10.4 Recovery of Costs by an Unregulated Transmitting Utility.

An Unregulated Transmitting Utility is a Transmission Owner that, pursuant to Section 201(f) of the FPA is not subject to the Commission's jurisdiction under Sections 205 and 206 of the FPA. The recovery of costs related to the preparation of proposals for, and the development, construction, operation and maintenance of, a regulated reliability transmission project undertaken pursuant to Attachment Y of the ISO OATT by LIPA, as an Unregulated Transmitting Utility, shall be conducted as follows:

6.10.4.1 Upon the request of the ISO, an Unregulated Transmitting Utility will proceed with the process of receiving any necessary authorization for the requested project.

6.10.4.2 Upon receipt of all necessary federal, state and local authorizations, the Unregulated Transmitting Utility shall commence with construction of the transmission project, including a transmission project identified pursuant to Section 31.2.11.9 of Attachment Y of the ISO OATT as a Gap Solution, in order to meet the Reliability Need by the need date.

**6.10.4.3 Cost Recovery for LIPA**

Transmission Owners other than LIPA that propose an alternative regulated transmission project on Long Island would recover any costs per Sections 6.10.2 through 6.10.3.4 of this Attachment. Other Developers that propose an alternative regulated transmission project on Long Island would recover any costs per Section 6.10.5 of this Attachment.

6.10.4.3.1 Any costs incurred for a regulated backstop reliability transmission project or an alternative regulated transmission project undertaken by LIPA, as an Unregulated Transmitting Utility, shall be recovered as follows:

6.10.4.3.1.1 For costs to LIPA customers: Cost will be recovered pursuant to a rate recovery mechanism approved by the Long Island Power Authority's Board of Trustees pursuant to Article 5, Title 1-A of the New York Public Authorities Law, Sections 1020-f(u) and 1020-s. Upon approval of the rate recovery mechanism, LIPA shall provide to the ISO, for purposes of inclusion within the ISO OATT and filing with FERC on an informational basis only, a description of the rate recovery mechanism and the rate that LIPA will charge and collect from responsible entities within the Long Island Transmission District in accordance with the ISO cost allocation methodology pursuant to Section 31.5.3.2 of Attachment Y of the ISO OATT.

6.10.4.3.1.2 For Costs to Other Transmission Districts: Where the ISO determines that there are responsible entities outside of the Long Island Transmission District that should be allocated a portion of the costs of the regulated backstop reliability transmission solution or an alternative regulated transmission solution undertaken by LIPA, LIPA shall inform the ISO of the amount of such costs. Such costs will be an allocable amount of the cost base recovered through the recovery mechanism described in Section 6.10.4.3.1.1 in accordance with the formula set forth in Section 6.10.3.4. The costs of a LIPA regulated backstop reliability transmission project or an alternative regulated transmission solution, allocable to responsible entities outside of the Long Island Transmission District shall constitute the "revenue requirement" that the ISO shall include and, and recover through, a separate "LIPA RFC". The ISO shall file the LIPA RFC with the Commission as an informational filing. The ISO will file such RFC for Commission review under the same "comparability" standard as is applied to review of changes in LIPA's TSC under Attachment H of this tariff. LIPA shall intervene in support of such filing at the Commission and shall take the responsibility to resolve all concerns about the contents of the filing that might be raised in such proceeding. The ISO shall bill for LIPA the LIPA RFC to responsible entities in Transmission Districts other than the Long Island Transmission District consistent with Sections 6.10.3.1 through 6.10.3.4 and shall remit the revenues collected to LIPA each Billing Period.

6.10.4.4 Savings Clause. The inclusion in the ISO OATT or in a FERC filing on an informational basis of the charges for recovery of costs incurred by LIPA or

NYPA related to a regulated project undertaken pursuant to Attachment Y into the ISO OATT, as provided for in Sections 6.10.4.3 and 6.10.4.4, or the inclusion of such charges in the ISO RFC pursuant to Section 6.10.4.3.1.2, shall not be deemed to modify the treatment of such rates as non-jurisdictional pursuant to Section 201(f) of the FPA.

**6.10.5 Recovery of Costs Incurred by an Other Developer Related to an Alternative Regulated Solution.**

6.10.5.1 The RFC shall be used as the cost recovery mechanism for the recovery of the costs of an alternative regulated transmission solution that: (i) has been selected by the ISO as the more efficient or cost effective solution to the identified Reliability Need, and is authorized by FERC to recover costs under this rate mechanism, or (ii) has been identified pursuant to Section 31.2.11.9 of Attachment Y of the ISO OATT as a Gap Solution to be implemented to address a Reliability Need. Provided however, nothing in this cost recovery mechanism shall be deemed to create any additional rights for an Other Developer to proceed with a regulated transmission project that such Other Developer does not otherwise have at law. The provisions of Sections 6.10.3 through 6.10.3.4 of this Attachment shall be applicable to the recovery of the costs incurred by an Other Developer for proposing, developing, constructing, operating, maintaining, and financing an alternative regulated transmission project that: (i) the ISO has selected as the more efficient or cost effective solution to the identified Reliability Need, or (ii) has been identified pursuant to Section 31.2.11.9 of Attachment Y of the ISO OATT as a Gap Solution to be implemented to address a Reliability Need.

6.10.5.2 Upon receipt of all necessary federal, state, and local authorizations, including FERC acceptance of a Section 205 filing authorizing cost recovery under the ISO tariff, the Other Developer shall commence construction of the transmission project, including a transmission project identified pursuant to Section 31.2.11.9 of Attachment Y of the ISO OATT as a Gap Solution, in order to meet the Reliability Need by the need date. Upon completion of the project, the Other Developer and/or the ISO, as applicable, will make a filing with FERC to provide the final project cost and resulting revenue requirement to be recovered pursuant to this Attachment. The resulting revenue requirement will become effective and recovery of project costs pursuant to this Attachment will commence upon the acceptance of the filing by FERC. This Section 6.10.5.2 also applies to the recovery of all reasonably incurred costs related to a project that the ISO has selected as the more efficient or cost effective solution, and is later halted in accordance with the provisions of the ISO OATT, including but not limited to reasonable and necessary expenses incurred to implement an orderly termination of the project.

6.10.5.3 Other Developers may also propose a non-transmission solution subject to state jurisdiction to address a Reliability Need included in the Comprehensive Reliability Plan.

## 6.14 Schedule 14 – Rate Mechanism for Recovery of RMR Generator Related Charges from and Payment of RMR Generator Related Credits to RMR LSEs

### 6.14.1 Applicability

The ISO will apply this Schedule separately for each RMR Generator operating under an RMR Agreement. For purposes of this Schedule, "RMR LSEs" are all the LSEs, including Transmission Owners, competitive LSEs and municipal systems, serving Load in the Load Zone or Subzone (as applicable) to which the charges and credits associated with an RMR Generator operating under an RMR Agreement are allocated.

Section 6.14.2 establishes how credits and charges to RMR LSEs will be allocated and recovered. Section 6.14.3 establishes how the ISO will calculate and recover the RMR Charge applicable to each RMR Generator operating under an RMR Agreement. The RMR Charge for a Billing Period may result in either a charge or a credit to the RMR LSEs. Sections 6.14.4 and 6.14.5 establish how the ISO will charge RMR LSEs any Performance Incentive payment or Availability Incentive payment owed to an RMR Generator with an RMR Agreement that contains an Availability and Performance Rate. Finally, Section 6.14.6 establishes how the ISO will allocate and credit to RMR LSEs any Capital Expenditure costs recovered from the RMR Generator by the ISO pursuant to Section 15.8.6 of Rate Schedule 8 to the Services Tariff.

### 6.14.2 Allocation of RMR Charges

Charges and credits to RMR LSEs under this Schedule will be allocated in accordance with Section 31.5.3 of Attachment Y to the ISO OATT. The ISO will charge or credit each RMR LSE based on its share of Actual Energy Withdrawals in the Load Zone or Subzone (as applicable) for the relevant Billing Period.

### 6.14.3 Calculation and Recovery of RMR Charge

#### 6.14.3.1 Applicability

The ISO will calculate the RMR Charge in accordance with Section 6.14.3.3 for each RMR Generator operating under an RMR Agreement that includes an Availability and Performance Rate. The ISO will calculate the RMR Charge in accordance with Section 6.14.3.4 for each RMR Generator operating under a rate that is not an Availability and Performance Rate.

#### 6.14.3.2 Assessing or Crediting the RMR Charge

If the RMR Charge calculated pursuant to Section 6.14.3.3 or 6.14.3.4, as applicable, is positive for a Billing Period, then the ISO will assess the RMR Charge to the RMR LSEs. If the RMR Charge calculated pursuant to Section 6.14.3.3 or 6.14.3.4, as applicable, is negative for a Billing Period, then the ISO will credit the absolute value of the RMR Charge to the RMR LSEs. Credits to the RMR LSEs are drawn from the revenue recovered from Transmission Customers as a result of the RMR Generator's participation in the ISO-Administered Markets during that Billing Period.

#### 6.14.3.3 Calculation of RMR Charge for an RMR Generator Providing Service Under an Availability and Performance Rate

$$RMRCharge_{l,g,P} = \sum_{d \in P} \left( \left( RMRAvoidCost_{g,d} + VarCost_{g,d} - MarketRev_{g,d} \right) * \sum_{z \in Z} \left( ZonalCostAllocation_{g,z} * \left( MWh_{l,z,d} / MWh_{z,d} \right) \right) \right)$$

*Where:*

$g$ = the relevant RMR Generator that is providing service under an Availability and Performance Rate;

$P$ = the relevant Billing Period;

$d$ = the relevant market day;

*l* = the relevant RMR LSE;

*z* = an individual NYCA Load Zone or Subzone (as applicable);

*Z* = the set of all Load Zones (or Subzones as applicable) that have nonzero allocations for the relevant RMR Generator;

$RMRCharge_{l,g,P}$ = the RMR Charge associated with RMR Generator *g* for Billing Period *P* for RMR LSE *l*;

$RMRAvoidCost_{g,d}$ = the RMR Avoidable Cost amount for RMR Generator *g* for day *d*, that has been accepted for filing by the Commission, or as calculated by the ISO in accordance with Sections 31.2.11.8 and 31.2.11.17 of the OATT pending Commission action, shaped on a Capability Period basis;

$VarCost_{g,d}$ = the Variable Cost amount for RMR Generator *g* for day *d*, calculated pursuant to Section 15.8.1 of Rate Schedule 8 to the ISO Services Tariff;

$MarketRev_{g,d}$ = the revenue recovered from Transmission Customers under the ISO Tariffs for day d in connection with the participation of the RMR Generator g in the ISO Administered Markets, including LBMP revenues, Ancillary Services revenues, guarantee or supplemental payments, Day-Ahead to real-time balancing settlements as described in Section 4 of the ISO Services Tariff, and monthly Capacity revenues divided by the number of days in the month;

$ZonalCostAllocation_{g,z}$ = the proportion of the cost of RMR Generator *g* allocated to Load Zone or Subzone (as applicable) *z*;

$MWh_{z,d}$ = Actual Energy Withdrawals in Load Zone or Subzone (as applicable) *z* aggregated across all hours on day *d*;

$MWh_{l,z,d}$ = Actual Energy Withdrawals for RMR LSE *l* in Load Zone or Subzone (as applicable) *z* aggregated across all hours on day *d*.

### 6.14.3.4 Calculation of RMR Charge for an RMR Generator Providing Service Under a Rate Other Than an Availability and Performance Rate

$$RMRCharge_{l,g,P} = \sum_{d \in P} \left( \left( RMRCost_{g,d} + VarCost_{g,d} - MarketRev_{g,d} \right) * \sum_{z \in Z} \left( ZonalCostAllocation_{g,z} * \left( MWh_{l,z,d} / MWh_{z,d} \right) \right) \right)$$

*Where:*

*g* = the relevant RMR Generator that is providing service under a rate other than an ISO-developed Availability and Performance Rate;

$RMRCost_{g,d}$ = the costs RMR Generator *g* is authorized to recover for day *d* pursuant to a rate approved for RMR Generator *g* by the Commission, or is recovering subject to refund pending Commission action, shaped on a Capability Period basis.

The definitions of the remaining variables in this equation are identical to the definitions for such variables set forth in Section 6.14.3.3 above.

### 6.14.4 Performance Incentive Payment

The ISO will charge the RMR LSEs on a monthly basis for any Performance Incentive payment owed to an RMR Generator pursuant to Section 15.8.3 of the ISO Services Tariff for its performance in that month in accordance with the formula in Section 6.14.4.1.

#### 6.14.4.1 Calculation of RMR Performance Incentive Charge

$$RMRPerformIncentCharge_{l,g,m} = RMRPerformIncentPayment_{g,m} * \sum_{z \in Z} \left( ZonalCostAllocation_{g,z} * \left( MWh_{l,z,m} / MWh_{z,m} \right) \right)$$

*Where:*

*m* = the billing month for which the performance was calculated;

$RMRPerformIncentCharge_{l,g,m}$ = the Performance Incentive Charge associated with RMR Generator *g* for billing month *m* for RMR LSE *l*;

$RMRPerformIncenPayment_{g,m}$ = the Performance Incentive amount for RMR Generator *g* for month *m*, calculated pursuant to Section 15.8.3 of Rate Schedule 8 to the ISO Services Tariff;

$MWh_{z,m}$ = Actual Energy Withdrawals in Load Zone or Subzone (as applicable) *z* aggregated across all hours in month *m*;

$MWh_{l,z,m}$ = Actual Energy Withdrawals for RMR LSE *l* in Load Zone or Subzone (as applicable) *z* aggregated across all hours in month *m*.

The definitions of the remaining variables in this equation are identical to the definitions for such variables set forth in Section 6.14.3.3 above.

### 6.14.5 Availability Incentive Payment

The ISO will charge the RMR LSEs on a Capability Period basis for any Availability Incentive payment owed to an RMR Generator pursuant to Section 15.8.4 of the ISO Services Tariff. The ISO will recover the Availability Incentive payment from RMR LSEs in the Billing Period following the first month of the Capability Period for any payment earned for the previous Capability Period in accordance with the formula in Section 6.14.5.1.

#### 6.14.5.1 Calculation of RMR Availability Incentive Charge

$$RMRAvailIncentCharge_{l,g,m} = RMRAvailIncentPayment_{g,m} * \sum_{z \in Z} \left( ZonalCostAllocation_{g,z} * \left( MWh_{l,z,m} / MWh_{z,m} \right) \right)$$

*Where:*

*m* = the first billing month after the Incentive from the previous Capability period was calculated;

$RMRAvailIncentCharge_{l,g,m}$ = the Availability Incentive Charge associated with RMR Generator *g* for billing month *m* for RMR LSE *l*;

$RMRAvailIncenPayment_{g,m}$ = the Availability Incentive amount for RMR Generator *g* for month *m*, calculated pursuant to Section 15.8.4 of Rate Schedule 8 to the ISO Services Tariff;

$MWh_{z,m}$ = Actual Energy Withdrawals in Load Zone or Subzone (as applicable) *z* aggregated across all hours in month *m*;

$MWh_{l,z,m}$ = Actual Energy Withdrawals for RMR LSE *l* in Load Zone or Subzone (as applicable) *z* aggregated across all hours in month *m*.

The definitions of the remaining variables in this equation are identical to the definitions for such variables set forth in Section 6.14.3.3 above.

### 6.14.6 Distribution of Recovered Capital Expenditure Costs

If, at any time, the ISO recovers from the RMR Generator any Capital Expenditure in accordance with Section 15.8.6 of the ISO Services Tariff, the ISO will credit the recovered costs

to the RMR LSEs in the next monthly invoice following receipt of the payment from the RMR Generator in accordance with the formula in Section 6.14.6.1.

#### 6.14.6.1 Calculation of RMR Capital Expenditure Credit

$$RMRCapExCredit_{l,g,m} = RMRCapExRecovery_{g,m} * \sum_{z \in Z} \left( ZonalCostAllocation_{g,z} * \left( MWh_{l,z,m} / MWh_{z,m} \right) \right)$$

*Where:*

*m* = the billing month in which the capital expenditure is recovered;

$RMRCapExCredit_{l,g,m}$ = the Capital Expenditure Credit associated with RMR Generator *g* for billing month *m* for RMR LSE *l*;

$RMRCapExRecovery_{g,m}$ = the Capital Expenditure Recovery from RMR Generator *g* for month *m*, calculated pursuant to Section 15.8.6 of Rate Schedule 8 to the ISO Services Tariff;

$MWh_{z,m}$ = Actual Energy Withdrawals in Load Zone or Subzone (as applicable) *z* aggregated across all hours in month *m*;

$MWh_{l,z,m}$ = Actual Energy Withdrawals for RMR LSE *l* in Load Zone or Subzone (as applicable) *z* aggregated across all hours in month *m*.

The definitions of the remaining variables in this equation are identical to the definitions for such variables set forth in Section 6.14.3.3 above.

## 12.4 Treatment of Confidential and Transmission System Information

This section deals with Confidential Information, including Transmission System Information. Confidential Information consists of: (1) data designated as such in NYPP Operating Policy OP-18 (or its successor); (2) any commercially sensitive information including, without limitation, trade secrets, equipment specific information (*e.g.,* Generator specific data such as heat rates, etc.), and business strategies, affirmatively designated as Confidential Information by its supplier or owner; and (3) Transmission System Information ("TSI") that has not yet been posted on the OASIS or provided in some public forum such as a FERC filing. TSI is information: (1) that is commercially valuable and (2) access to which is necessary to buy, sell or schedule Energy, Capacity, Ancillary Services or Transmission Service. Examples of TSI include, but are not limited to, the following:

- Available Transfer Capability;
- Total Transfer Capability;
- Information regarding physical Curtailments and Interruptions;
- Information regarding Ancillary Services;
- Pricing for Transmission Service; and
- Discounts offered.

In the course of responding to requests for Energy, Capacity, Transmission Services or Ancillary Services, the ISO shall not disclose Confidential Information to any Market Participant. The ISO shall disclose data that is not Confidential Information, and information required to be disclosed by FERC, by posting the information on the OASIS. If an ISO Employee improperly discloses TSI to any Market Participant, the ISO shall immediately post the information on the OASIS and notify the Commission.

ISO Employees shall also report all improper disclosures of Confidential Information to the ISO compliance officer (as described in Section 12.10) or its designee immediately. In the case of an Emergency, the ISO may disclose such TSI, and then notify the Commission, posting the information on the OASIS as soon as practicable but no later than twenty-four (24) hours after the information is disclosed.

The procedures described in this section do not apply to the following:

(1) communication of TSI between the ISO and the Transmission Owner's control centers, and other power pools or ISOs;

(2) communication of non-public, operational information concerning natural gas-fueled generation from resources located within the New York Control Area between the ISO and the operating personnel of an interstate natural gas pipeline company for the purpose of promoting reliable service or operational planning;

(3) communication of non-public, operational information concerning natural gas-fueled generation from resources located within the New York Control Area between the ISO and the operating personnel of natural gas local distribution companies ("LDCs") and/or intrastate natural gas pipeline companies for the purpose of promoting reliable service or operational planning, if such party has acknowledged, in writing, that it is prohibited from disclosing—or using anyone as a conduit for disclosure of—non-public, operational information received from the ISO to: (a) an employee other than operating personnel of that LDC and/or intrastate natural gas pipeline company, (b) a third party, or (c) any affiliate except for (i) the operating personnel of an affiliated interstate natural gas pipeline company, or (ii) the operating personnel of an intrastate pipeline which has a non-

disclosure agreement with the ISO. The operating personnel of an affiliated interstate natural gas pipeline company accepting non-public operational information pursuant to this section shall agree to comply with 18 CFR 284.12(b)(4)(ii). Unless otherwise authorized by the Commission, for purposes of this section LDC or intrastate pipeline "operating personnel" shall exclude employees engaged in marketing functions as defined by 18 CFR 358.3(c) or who make sales of natural gas;

(4) communication of information from a Market Participant to the ISO;

(5) information that is no longer Confidential Information because it was made public by posting it on the OASIS; or it was legally disclosed by a third party in good faith and without violating a trade secret, secrecy agreement or employment contract with a non-disclosure clause; or it was made public by a government agency, court or other process of law;

(6) requests by a Market Participant for a report regarding the status of that Market Participant's particular contracts or transactions. The ISO shall provide all Market Participants requesting a report the same type and level of detail of information;

(7) information that is not listed in NYPP OP-18 and has not been designated by the supplier or owner as Confidential Information;

(8) disclosures by the ISO that are authorized under ISO Services Tariff Attachment H Section 23.4.5.7 and its subsections (except as restricted in section 23.4.5.7.3.2);

(9) identification of a Generator first entering service, becoming Retired, or entering into or returning from a Mothball Outage or ICAP Ineligible Forced Outage, including dates thereof; and

(10) New York State Transmission System reliability impacts that would occur if a Generator were unavailable due to events such as becoming Retired or entering a Mothball Outage or ICAP Ineligible Forced Outage.

If Confidential Information is required to be divulged in compliance with an order or a subpoena of a court or regulatory body other than FERC or the Commodity Futures Trading Commission ("CFTC"), the ISO will seek to obtain a protective order or other appropriate protective relief from the court or regulatory body, provided, however, that the ISO staff shall not be required to do any additional analysis to produce such information. With the exception of requests for Confidential Information submitted to the ISO from FERC or the CFTC, the ISO shall provide advance written or electronic notice to the parties providing the Confidential Information as soon as practicable upon receipt of such an order or a subpoena from a court or regulatory body, and the ISO shall not be held liable for any losses, consequential or otherwise, resulting from the ISO divulging such Confidential Information pursuant to a subpoena or an order of a court or regulatory body.

The ISO is required to provide data and information to the FERC or its staff, pursuant to FERC Order No. 760,[1] that is otherwise required to be maintained in confidence pursuant to this section. FERC Order No. 760 requires the ISO to engage in the ongoing electronic delivery of data related to physical and virtual offers and bids, market awards, resource outputs, marginal

[1] *Enhancement of Electricity Market Surveillance and Analysis Through Ongoing Electronic Delivery of Data From Regional Transmission Organizations and Independent System Operators*, Order No. 760, 139 FERC ¶ 61,053 (2012) ("Order No. 760" or "the Order").

cost estimates, shift factors, TCCs, internal bilateral contracts, interchange pricing, capacity markets and uplift charges and credits. The ISO shall provide the data described in FERC Order No. 760 to the FERC or its staff on a continuous basis.

If the FERC or CFTC or their staff, during the course of an investigation or otherwise, requests information, in addition to the ongoing electronic delivery pursuant to FERC Order No. 760, from the ISO that is otherwise required to be maintained in confidence pursuant to this section, the ISO shall provide the requested information to the FERC or CFTC or their staff within the time provided for in the request for information. In providing the ongoing electronic delivery or additional requested information to the FERC or its staff or information requested by the CFTC, the ISO shall, consistent with any FERC or CFTC rules or regulations that may provide for privileged treatment of that information, request that the information be treated as confidential and non-public by the FERC or CFTC and their staff and that the information be withheld from public disclosure. The ISO shall not be held liable for any losses, consequential or otherwise, resulting from the ISO divulging such Confidential Information pursuant to the ongoing electronic delivery or an additional request under this paragraph.

After Confidential Information has been provided to the FERC or CFTC or their staff, the ISO shall immediately notify any affected Market Participant(s) when it becomes aware that a request for disclosure of such Confidential Information has been received by the FERC or CFTC or their staff, or a decision to disclose such Confidential Information has been made by the FERC or CFTC, at which time the ISO and the affected Market Participant(s) may respond before such information would be made public, pursuant to the FERC's and CFTC's rules and regulations that may provide for privileged treatment of information provided to the FERC or CFTC or their staff.

The ISO shall establish procedures for handling Confidential Information that minimize the possibility of intentional or accidental improper disclosure.

### 12.4.1 Insider Trading

This section defines insider trading, explain the duties of ISO Employees and describes behavior that is prohibited under securities laws.

#### 12.4.1.1 Insider Information:

Federal laws prohibit the purchase or sale of any publicly traded security by a person in possession of important information about the security or its issuer that is not publicly known. These laws have special significance to the ISO because ISO Employees routinely learn of Confidential Information about Market Participants and others. This circumstance creates two duties for all ISO Employees: (1) a duty not to trade while in possession of "material, nonpublic information," also known as "inside information" or "insider information," as defined below, and (2) a duty not to communicate such information to anyone outside of the ISO, also known as "tipping." It has been and remains the policy of the ISO that there be scrupulous compliance with each of these duties.

Material: Much of the information obtained about Market Participants and any of their Affiliates may be material information under the law. Information is material if a reasonable investor would consider it important in determining whether to buy or sell the securities of the company involved. The information may be either positive or negative. If the information would affect the price of the stock, it is material. If the information makes you or anyone else think about wanting to buy or sell the stock, that is probably the best indication that it is material. Some examples of information that could be considered material are key personnel changes, earnings information, fines or assessments that the ISO imposes on the company, and

Confidential Information (as described in Section 12.4) including information relating to future generation capacity. If in doubt, one should assume that any information which could have any significance to an investor is material and not purchase or sell or allow anyone else to purchase or sell the securities in question until such information has been made public.

Nonpublic: Information that has not been disclosed to the public generally is nonpublic. To show that information is public, one should be able to point to some evidence that it is widely disseminated. Information would generally be deemed widely disseminated if it has been disclosed, for example, in the Dow Jones broad tape; news wire services such as AP or Reuters; radio or television; newspapers or magazines; the OASIS; or widely circulated public disclosure documents filed with the federal Securities and Exchange Commission ("SEC"), such as prospectuses or proxies.

Although it is natural to "talk shop," no Confidential Information should be given to outsiders; for this purpose "outsiders" include one's immediate family (as defined in Section 12.7), relatives, friends and anyone else other than those working on the matter at the ISO. In general, ISO matters should not be discussed with any outside individuals. Particular care is necessary in discussing ISO matters in elevators, restaurants, taxicabs, trains, commercial aircraft and other public places where names and other scraps of information might be overheard. Care should also be taken not to expose nonpublic papers in such places or leave them lying around in conference rooms or other places even within the ISO.

#### 12.4.1.2 Penalties for Trading on Insider Information

It is against ISO policy and a violation of law to make use of insider information for personal advantage in securities trading or to disclose such information to an outsider. ISO Employees who have any knowledge or insider trading activities or improper disclosure

committed by other ISO Employees must immediately notify the ISO compliance officer (as described in Section 12.10) or his designee. ISO Employees who have engaged in insider trading or have provided insider information to outsiders will be terminated immediately. In addition, both the ISO and the ISO Employee may be subject to severe civil and criminal penalties as a result of insider trading by the ISO Employee or by an outsider who has received insider information from the ISO Employee.

## 25.9 Going Forward

### 25.9.1 ERIS Election and future Evaluation for CRIS

Whenever a Developer elects to interconnect taking ERIS, that Developer may, at any later date, ask the NYISO to evaluate the Developer's Large Facility or Small Generating Facility for CRIS by including the Developer's Large Facility or Small Generating Facility in the Open Class Year and the Deliverability Study to be conducted for that Class Year.

### 25.9.2 No Developer Responsibility for Future Upgrades

Once a Developer has posted Security for its share of the System Upgrade Facilities required for its project, and paid cash or posted Security for its share of the System Deliverability Upgrades required for its project, then, except as provided in Section 25.8.6 of these rules, that Developer has no further responsibility for the cost of additional Attachment Facilities, Distribution Upgrades System Upgrade Facilities and System Deliverability Upgrades that may be required in the future.

25.9.2.1 The Project interconnection agreement executed between a Developer and its Connecting Transmission Owner will reflect the Developer's responsibility for the cost of new Attachment Facilities, Distribution Upgrades and System Upgrade Facilities and System Deliverability Upgrades, as that responsibility has been determined in accordance with these rules.

25.9.2.2 The cost of those additional Attachment Facilities, Distribution Upgrades, System Upgrade Facilities and System Deliverability Upgrades needed for future interconnection projects will be shared between future Developers and Transmission Owners, and allocated among future Developers, in accordance with the rules.

### 25.9.3 Term of CRIS Rights

#### 25.9.3.1 Retaining CRIS Status

Large Facilities and Small Generating Facilities qualifying for CRIS will retain their CRIS Status at the capacity level found deliverable in the Class Year Deliverability Study regardless of subsequent changes to the transmission system or the transfer of facility ownership, provided the facility remains capable of operating at the capacity level studied and is not CRIS-inactive for more than three (3) continuous years. For the purpose of the rules in this Section 25.9.3, and in Sections 25.9.4 and 25.9.5 of Attachment S, a facility becomes CRIS-inactive on the last day of the month during which (i) it ceases to offer capacity into NYISO capacity auctions, or (ii) it ceases to be registered as a Capacity Resource for a Load Serving Entity through a bilateral transaction(s) or self-supply arrangement. For Large Facilities and Small Generating Facilities pre-dating Class Year 2007, *i.e.*, facilities interconnected or completely studied for interconnection before the projects in Class Year 2007, the facility shall qualify for CRIS service so long as (i) it is not retired (*e.g.*, identified as retired in a NYISO Load and Capacity Data Report prior to October 5, 2008, (ii) its interconnection agreement is not terminated, and (iii) the facility begins commercial operations within three years of the commercial operation date or comparable commencement date specified in its initial interconnection agreement filing. A generator or merchant transmission facility pre-dating Class Year 2007 without an interconnection agreement on October 5, 2008, or one with an initial interconnection agreement filing that does not specify a commercial operation date or any comparable commencement date, shall qualify for CRIS so long as it is not retired (*e.g.*, identified as retired in a NYISO Load and Capacity Data Report) prior to October 5, 2008 and it begins commercial operations within three years of its in-service date specified in the 2008 NYISO Load and Capacity Data Report. For generators pre-dating Class Year 2007, the CRIS

capacity level will be set at the maximum DMNC level achieved during the five most recent Summer Capability Periods prior to October 5, 2008, even if that DMNC value exceeds nameplate MWs.

For a generator pre-dating Class Year 2007 and not having DMNC levels recorded for five Summer Capability Periods prior to October 5, 2008, its CRIS capacity level will be set, and reset if necessary, at the maximum DMNC level achieved during successive Summer Capability Periods until it has DMNC levels recorded for five Summer Capability Periods. Prior to the establishment of the generator's first DMNC value for a Summer Capability Period, the generator's CRIS level will be set at nameplate MW. The CRIS capacity level for intermittent resources pre-dating Class Year 2007 will be set at nameplate MW, and the CRIS capacity level for controllable lines pre-dating Class Year 2007 will be set at the MW of Unforced Capacity Deliverability Rights awarded to them. In the case of a CRIS-inactive Large Facility or Small Generating Facility, the facility's CRIS status at the capacity level eligible for CRIS found deliverable terminates three years after the facility becomes CRIS-inactive, except as provided in Sections 5.18.2.3.2, 5.18.3.3.2, and 5.18.5 of the Services Tariff, unless the CRIS-inactive facility takes one of the following actions before the end of the three-year period: (1) returns to service and participation in NYISO capacity auctions or bilateral transactions, or (2) transfers capacity deliverability rights to another Large Facility or Small Generating Facility at the same or a different electrical location that becomes operational within three years from the deactivation of the original facility.

**25.9.3.2 Term of External CRIS Rights**

25.9.3.2.1 The initial term of External CRIS Rights, whether based on a Contract or Non-Contract Commitment, will be for an Award Period of no less than five (5) years.

25.9.3.2.2 An entity holding External CRIS Rights may renew those rights for one or more subsequent terms, as described below:

25.9.3.2.2.1 An entity holding External CRIS Rights based on a Contract Commitment may renew its External CRIS Rights, provided that the NYISO receives from the entity a request to renew on or before the date specified in Section 25.9.3.2.2.3 indicating that the entity has renewed its bilateral contract to supply External Installed Capacity for an additional term of no less than five (5) years. If the entity does so, then that entity's External CRIS Rights will be renewed for the same additional term, without any further evaluation of the deliverability of the External Installed Capacity covered by the renewed bilateral contract.

25.9.3.2.2.2 An entity holding External CRIS Rights based on a Non-Contract Commitment may renew its External CRIS Rights, provided that the NYISO receives from the entity a request to renew on or before the date specified in Section 25.9.3.2.2.3. Any Non-Contract Commitment renewal must be for an additional term of no less than five (5) years. If the entity does so, then that entity's External CRIS Rights will be renewed for the same additional term, without any further evaluation of the deliverability of the External Installed Capacity associated with the Non-Contract Commitment.

25.9.3.2.2.3 Requests for renewal of External CRIS Rights must be received by the NYISO on or before a date defined by the earlier of: (i) six months prior to the

expiration date of the Contract or Non-Contract Commitment, or (ii) one month prior to the Study Start Date of the ATRA that is prior to the start of the last Summer Capability Period within the current Award Period or renewal of an Award Period.

25.9.3.2.3 External CRIS Rights will terminate at the end of the effective Award Period or renewal of an Award Period if those rights have not been renewed for an additional term, pursuant to the process described above.

### 25.9.4 Transfer of Deliverability Rights - Same Location

If a facility deactivates an existing unit within the NYCA and commissions a new one at the same electrical location, the CRIS status of the deactivated facility and its deliverable capacity level may be transferred to that same electrical location, provided that the new facility becomes operational within three years from the deactivation of the original facility. The new facility will only acquire the assigned capacity deliverability rights once the new facility becomes operational. Capacity rights will be stated in MWs of Installed Capacity. In the case of transfers between the same or different resource types, those MWs of Installed Capacity will be adjusted by the derate factor applicable to the existing facility (based on the asset-class derate factors used in the most recent Class Year Deliverability Study) before the transfer and, following the transfer, will be readjusted to MWs of Installed Capacity in accordance with the derate factor applicable to the new facility (based on the asset-class derate factors used in the most recent Class Year Deliverability Study).

### 25.9.5 Transfer of Deliverability Rights - Different Locations

Rights may also be transferred on a bilateral basis between an existing facility within the NYCA and a new facility at a different location within the NYCA to the extent that the new

facility is found to be deliverable after the existing facility assumes ERIS status or deactivates. The new facility may contract with an existing facility (with assigned capacity rights) to transfer some or all of the existing facility's assigned capacity rights. The new facility will be allowed to acquire these rights if it meets the deliverability test executed in the following manner:

25.9.5.1 Prior to the Class Year Deliverability Study, the new and existing facilities involved in the transfer transaction must tell the NYISO the MW level of capacity rights proposed to be transferred. Capacity rights will be stated in MWs of Installed Capacity. In the case of transfers between different resource types, those MWs of Installed Capacity will be adjusted by the derate factor applicable to the existing facility before the transfer and, following the transfer, will be readjusted to MWs of Installed Capacity in accordance with the derate factor applicable to the new project. All derate factors will be based on the asset-class derate factors in the current Class Year Deliverability Study.

25.9.5.1.1 The NYISO will evaluate the deliverability of the Class Year projects together, with no transfers, to determine the extent to which new facilities in the Class Year that are parties to proposed transactions are deliverable without the proposed transfers.

25.9.5.1.2 The NYISO will then reduce the output of all established facilities that are parties to proposed transactions to see if the new facility counterparties benefit, *i.e.*, their undeliverable capacity is made deliverable, from the proposed transfers; provided, however, the established facilities will be reduced only to the extent that their reduction does not adversely impact the deliverability of Class Year projects that are not parties to the proposed transactions.

25.9.5.1.3 If the deliverability test conducted by the NYISO shows that the new Class Year projects that are parties to the proposed transactions are fully or partially deliverable with these reductions of the established facility counterparties, then the new projects will be given five business days to notify the NYISO as to whether their particular transaction is final or not. If any proposed transactions are not finalized, then Sections 25.9.5.1.1 and 25.9.5.1.2 will be repeated until all proposed transactions have been terminated or finalized.

25.9.5.2 For each finalized transaction, the existing facility that is a party to the transaction will be modeled in Class Year Interconnection Facilities Study at its reduced output level (current level less CRIS finally transferred adjusted by the applicable derate factors). The Deliverability of Class Year Projects not parties to finalized transactions may benefit, but will not be adversely affected, by those transactions.

25.9.5.3 The existing facility will be restricted in future capacity sales up to levels consistent with the CRIS rights that were transferred to the new project counterparty.

25.9.5.4 The new project will only acquire the assigned capacity rights once the new project becomes operational at the levels necessary to utilize those rights.

**25.9.6 Transfer of External CRIS Rights**

A holder of External CRIS Rights may transfer some or all of the Contract or Non-Contract CRIS MW that it holds to another entity, provided that the following requirements are met:

25.9.6.1 The entity to receive the External CRIS Rights must, prior to the transfer, make either (i) a Contract Commitment of External Installed Capacity satisfying the requirements of Section 25.7.11.1.1 of this Attachment S, or (ii) a Non-Contract Commitment of External Installed Capacity satisfying the requirements of Section 25.7.11.1.2 of this Attachment S; and

25.9.6.2 The External Installed Capacity of the entity to receive the External CRIS Rights must use the same External Interface(s) used by the External Installed Capacity of the entity currently holding the External CRIS Rights; and

25.9.6.3 The transfer must be for the remaining duration of the Award Period or renewal of an Award Period currently effective for the External CRIS Rights to be transferred; and

25.9.6.4 If the holder of External CRIS Rights transfers some, but not all of its CRIS MW, the number of CRIS MW transferred must be such that, following the transfer, both the holder and the entity receiving External CRIS Rights satisfy the applicable requirements of Section 25.7.11.1.1 and 25.7.11.1.2 of this Attachment S; and

25.9.6.5 The transfer must take place on or before the earlier of:

25.9.6.5.1 Six months prior to the expiration date of the Contract or Non-Contract Commitment of the entity currently holding the External CRIS Rights to be transferred; or

25.9.6.5.2 One month prior to the Study Start Date of the ATRA that is prior to the start of the last Summer Capability Period within the current Award Period or renewal of an Award Period.

## 31.1 New York Comprehensive System Planning Process ("CSPP")

### 31.1.1 Definitions

Throughout Sections 31.1 through 31.10, the following capitalized terms shall have the meanings set forth in this subsection:

**Affected TO:** The Transmission Owner who receives written notification of a dispute related to a Local Transmission Planning Process pursuant to Section 31.2.1.4.1.

**Bounded Region:** A Load Zone or Zones within an area that is isolated from the rest of the NYCA as a result of constrained interface limits.

**CARIS:** The Congestion Assessment and Resource Integration Study for economic planning developed by the ISO in consultation with the Market Participants and other interested parties pursuant to Section 31.3 of this Attachment Y.

**CRP:** The Comprehensive Reliability Plan as approved by the ISO Board of Directors pursuant to this Attachment Y.

**CSPP:** The Comprehensive System Planning Process set forth in this Attachment Y, and in the Interregional Planning Protocol, which covers reliability planning, economic planning, Public Policy Requirements planning, cost allocation and cost recovery, and the interregional planning process.

**Developer:** A person or entity, including a Transmission Owner, sponsoring or proposing a project pursuant to this Attachment Y.

**ESPWG:** The Electric System Planning Work Group, or any successor work group or committee designated to fulfill the functions assigned to the ESPWG in this tariff.

**Gap Solution:** A temporary solution to a Reliability Need that may become a permanent solution and shall strive to be compatible with permanent market-based and regulated solutions, as applicable. A permanent regulated solution, if appropriate, may proceed in parallel with a Gap Solution.

**Generator Deactivation Assessment:** The ISO's analysis, in coordination with the Responsible Transmission Owner(s), of whether a Reliability Need will result from a Generator becoming Retired, entering into a Mothball Outage, or being unavailable due to an ICAP Ineligible Forced Outage.

**Generator Deactivation Assessment Start Date:** The date on which: (i) the ISO issues a written notice to a Market Participant pursuant to Section 31.2.11.2.2 indicating that the Generator Deactivation Notice for its Generator is complete, or (ii) a Market Participant's

Generator enters into an ICAP Ineligible Forced Outage pursuant to Section 5.18.2.1 of the ISO Services Tariff.

**Generator Deactivation Notice:** The form set forth in Section 31.8 (Appendix E) of this Attachment Y.

**Initiating Generator:** A Generator that submits a Generator Deactivation Notice for purposes of becoming Retired or entering into a Mothball Outage or that has entered into an ICAP Ineligible Forced Outage pursuant to Section 5.18.2.1 of the ISO Services Tariff, which action is being evaluated by the ISO in accordance with its Gap Solution process requirements in Section 31.2.11.

**Interregional Planning Protocol:** The Amended and Restated Northeastern ISO/RTO Planning Coordination Protocol, or any successor to that protocol.

**Interregional Transmission Project:** A transmission facility located in two or more transmission planning regions that is evaluated under the Interregional Planning Protocol and proposed to address an identified Reliability Need, congestion identified in the CARIS, or a transmission need driven by a Public Policy Requirement pursuant to Order No. 1000 and the provisions of this Attachment Y.

**IPTF:** The Interregional Planning Task Force, or any successor ISO stakeholder working group or committee, designated to fulfill the functions assigned to the IPTF in this tariff.

**ISO/RTO Region:** One or more of the three ISO or RTO regions known as PJM, ISO-New England, and NYISO, which are the "Parties" to the Interregional Planning Protocol.

**LCR:** An abbreviation for the term Locational Minimum Installed Capacity Requirement, as defined in the ISO Open Access Transmission Tariff.

**Loss of Load Expectation ("LOLE"):** A measure used to determine the amount of resources needed to minimize the possibility of an involuntary loss of firm electric load on the New York State Bulk Power Transmission Facilities.

**LTP:** The Local Transmission Owner Plan, developed by each Transmission Owner, which describes its respective plans that may be under consideration or finalized for its own Transmission District.

**LTP Dispute Resolution Process ("DRP"):** The process for resolution of disputes relating to a Transmission Owner's LTP set out in Section 31.2.1.4.

**LTPP:** The Local Planning Process conducted by each Transmission Owner for its own Transmission District.

**Management Committee:** The standing committee of the ISO of that name created pursuant to the ISO Agreement.

**Market Party:** shall mean any person or entity that is, or proposes or plans (including any participant therein,) a project that would be, a buyer or a seller in, or that makes bids or offers to buy or sell in, or that schedules or seeks to schedule Transactions with the ISO in or affecting any of the ISO Administered Markets, or any combination of the foregoing.

**Net CONE:** The value representing the cost of new entry, net of energy and ancillary services revenues, utilized by the ISO in establishing the ICAP Demand Curves pursuant to Section 5 of the ISO Market Services Tariff.

**New York State Bulk Power Transmission Facilities ("BPTFs"):** The facilities identified as the New York State Bulk Power Transmission Facilities in the annual Area Transmission Review submitted to NPCC by the ISO pursuant to NPCC requirements.

**NPCC:** The Northeast Power Coordinating Council, or any successor organization.

**NYCA Free Flow Test:** A NYCA unconstrained internal transmission interface test, performed by the ISO to determine if a Reliability Need is the result of a statewide resource deficiency or a transmission limitation.

**NYDPS:** The New York State Department of Public Service, as defined in the New York Public Service Law.

**NYISO Load and Capacity Data Report**: As defined in Section 25 of the ISO OATT.

**NYPSC**: The New York Public Service Commission, as defined in the New York Public Service Law.

**Operating Committee:** The standing committee of the ISO of that name created pursuant to the ISO Agreement.

**Order No. 1000:** The Final Rule entitled Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, issued by the Commission on July 21, 2011, in Docket RM10-23-001, as modified on rehearing, or upon appeal. (See FERC Stats & Regs. ¶ 31,323 (2011) ("Order No. 1000"), on reh'g and clarification, 139 FERC ¶ 61,132 ("Order No. 1000-A"), on reh'g and clarification, 141 FERC ¶ 61,044 (2012) ("Order No. 1000-B").

**Other Developer:** A Developer, other than a Transmission Owner, sponsoring or proposing to sponsor a regulated economic project, a Public Policy Transmission Project, an Other Public Policy Project, or a regulated solution to a Reliability Need.

**Other Public Policy Project:** A non-transmission project or a portfolio of transmission and non-transmission projects proposed by a Developer to satisfy an identified Public Policy Transmission Need.

**Owner**: (a) the entity or entities that have executed an RMR Agreement and assumed ultimate responsibility for the operation of an RMR Generator and its participation in the ISO Administered Markets; or (b) the entity or entities that have indicated their willingness to execute

an RMR Agreement and assume ultimate responsibility for the operation of an RMR Generator and its participation in the ISO Administered Markets by submitting a filing to FERC proposing a rate for providing RMR service or seeking to recover the cost of Capital Expenditures. Owner may be a Market Party and/or a Market Participant, may include one or more Market Parties and/or Market Participants, or may participate in the ISO Administered Markets by and through one or more Market Parties and/or Market Participants.

**Public Policy Transmission Planning Process:** The process by which the ISO solicits needs for transmission driven by Public Policy Requirements, evaluates all proposed Public Policy Transmission Projects and Other Public Policy Projects on a comparable basis, and selects the more efficient or cost effective Public Policy Transmission Project, if any, for eligibility for cost allocation under the ISO Tariffs.

**Public Policy Transmission Need:** A transmission need identified by the NYPSC that is driven by a Public Policy Requirement pursuant to Sections 31.4.2.1 through 31.4.2.3.

**Public Policy Transmission Planning Report:** The report approved by the ISO Board of Directors pursuant to this Attachment Y on the ISO's evaluation of all Public Policy Transmission Projects and Other Public Policy Projects proposed to satisfy an identified Public Policy Transmission Need pursuant to Section 31.4.6 and the ISO's selection of a proposed Public Policy Transmission Project, if any, that is the more efficient or cost effective solution to the identified Public Policy Transmission Need pursuant to Section 31.4.8.

**Public Policy Requirement:** A federal or New York State statute or regulation, including a NYPSC order adopting a rule or regulation subject to and in accordance with the State Administrative Procedure Act, any successor statute, or any duly enacted law or regulation passed by a local governmental entity in New York State, that may relate to transmission planning on the BPTFs.

**Public Policy Transmission Project:** A transmission project or a portfolio of transmission projects proposed by Developer(s) to satisfy an identified Public Policy Transmission Need and for which the Developer(s) seek to be selected by the ISO for purposes of allocating and recovering the project's costs under the ISO OATT.

**Reliability Criteria:** The electric power system planning and operating policies, standards, criteria, guidelines, procedures, and rules promulgated by the North American Electric Reliability Corporation ("NERC"), Northeast Power Coordinating Council ("NPCC"), and the New York State Reliability Council ("NYSRC"), as they may be amended from time to time.

**Reliability Need:** A condition identified by the ISO as a violation or potential violation of one or more Reliability Criteria and, for purposes of administering the Gap Solution process in Section 31.2.11, applicable local criteria.

**Responsible Transmission Owner:** The Transmission Owner or Transmission Owners designated by the ISO: (i) pursuant to Section 31.2.4.3, to prepare a proposal for a regulated backstop solution to a Reliability Need or to proceed with a regulated solution to a Reliability Need, or (ii) pursuant to Section 31.2.11.3, to prepare a Gap Solution and a conceptual

permanent solution to a Reliability Need. The Responsible Transmission Owner will normally be the Transmission Owner in whose Transmission District the ISO identifies a Reliability Need.

**RMR Start Date:** The date an RMR Generator begins participating, offering, and operating in the ISO-Administered Markets pursuant to the Tariff rules that apply to RMR Generators and the terms of an RMR Agreement.

**RNA:** The Reliability Needs Assessment as approved by the ISO Board under this Attachment.

**RNA Base Case:** The model(s) representing the New York State Power System over the Study Period.

**Site Control:** Documentation reasonably demonstrating: (1) ownership of, a leasehold interest in, or a right to develop a site or right of way for the purpose of constructing a proposed project; (2) an option to purchase or acquire a leasehold site or right of way for such purpose; or (3) an exclusivity or other business relationship between the Transmission Owner, or Other Developer, and the entity having the right to sell, lease, or grant the Transmission Owner, or Other Developer, the right to possess or occupy a site or right of way for such purpose.

**Study Period:** The ten-year time period evaluated in the RNA and the CRP.

**Target Year**: The calendar year in which a Reliability Need arises, as determined by the ISO pursuant to Section 31.2.

**TPAS:** The Transmission Planning Advisory Subcommittee, or any successor work group or committee designated to fulfill the functions assigned to TPAS pursuant to this Attachment.

**Trigger Date**: The date by which the ISO must request implementation of a regulated backstop solution or an alternative regulated solution pursuant to Section 31.2.8 in order to meet a Reliability Need.

**Viability and Sufficiency Assessment**: The results of the ISO's assessment of the viability and sufficiency of proposed solutions to a Reliability Need under Section 31.2.5 or a Public Policy Transmission Need under Section 31.4.6, as applicable.

**Viable and Sufficient Gap Solution:** A proposed Gap Solution pursuant to Section 31.2.11.3 or a Generator identified by the ISO pursuant to Section 31.2.11.4 that the ISO has determined in accordance with Section 31.2.11.6 to be viable and sufficient to satisfy the identified Reliability Need individually or in conjunction with other solutions.

All other capitalized terms shall have the meanings provided for them in the ISO's Tariffs.

### 31.1.2 Reliability Planning Process

Sections 31.2.1 through 31.2.13 of this Attachment Y describe the process that the ISO, the Transmission Owners, and Market Participants and other interested parties shall follow for local transmission planning, planning to meet the Reliability Needs of the BPTFs, and addressing the need for Gap Solutions. The objectives of the process are to: (1) evaluate the Reliability Needs of the BPTFs pursuant to Reliability Criteria (2) identify, through the development of appropriate scenarios, factors and issues that might adversely impact the reliability of the BPTFs; (3) provide a process whereby solutions to identified needs are proposed, evaluated on a comparable basis, and implemented in a timely manner to ensure the reliability of the system; (4) provide a process by which the ISO will select the more efficient or cost effective regulated transmission solution to satisfy the Reliability Need for eligibility for cost allocation under the ISO Tariffs; (5) provide an opportunity first for the implementation of market-based solutions while ensuring the reliability of the BPTFs; and (6) coordinate the ISO's reliability assessments with neighboring Control Areas. To the extent the ISO cannot timely satisfy an identified Reliability Need in its biennial reliability planning process, the ISO will commence the Gap Solution process in Section 31.2.11 to address the Reliability Need.

The ISO will provide, through the analysis of historical system congestion costs, information about historical congestion including the causes for that congestion so that Market Participants and other stakeholders can make appropriately informed decisions. See Appendix A.

### 31.1.3 Transmission Owner Planning Process

The Transmission Owners will continue to plan for their transmission systems, including the BPTFs and other NYS Transmission System facilities. The planning process of each

Transmission Owner is referred to herein as the LTPP, and the plans resulting from the LTPP are referred to herein as LTPs, whether under consideration or finalized. Each Transmission Owner will be responsible for administering its LTPP and for making provisions for stakeholder input into its LTPP. The ISO's role in the LTPP is limited to the procedural activities described in this Attachment Y.

The finalized portions of the LTPs periodically prepared by the Transmission Owners will be used as inputs to the CSPP described in this Attachment Y. Each Transmission Owner will prepare an LTP for its transmission system in accordance with the procedures described in Section 31.2.1.

### 31.1.4 Economic Planning Process

Sections 31.3.1 and 31.3.2 of this Attachment Y describe the process that the ISO, the Transmission Owners, and Market Participants shall follow for economic planning to identify and reduce current and future projected congestion on the BPTFs. The objectives of the economic planning process are to: (1) project congestion on the BPTFs over the ten-year planning period of this CSPP, (2) identify, through the development of appropriate scenarios, factors that might produce or increase congestion, (3) provide a process whereby projects to reduce congestion identified in the economic planning process are proposed and evaluated on a comparable basis in a timely manner, (4) provide an opportunity for the development of market-based solutions to reduce the congestion identified, and (5) coordinate the ISO's congestion assessments and economic planning process with neighboring Control Areas.

### 31.1.5 Public Policy Transmission Planning Process

Section 31.4 of this Attachment Y describes the planning process that the ISO, and all interested parties, shall follow to consider Public Policy Requirements that drive the need for

expansions or upgrades to BPTFs. The objectives of the Public Policy Transmission Planning Process are to: (1) allow Market Participants and other interested parties to propose transmission needs that they believe are being driven by Public Policy Requirements and for which transmission solutions should be evaluated, (2) provide a process by which the NYPSC will, with input from the ISO, Market Participants, and other interested parties, identify the transmission needs, if any, for which transmission solutions should be evaluated, (3) provide a process whereby Public Policy Transmission Projects and Other Public Policy Projects are proposed to satisfy each identified Public Policy Transmission Need and are evaluated by the ISO on a comparable basis, (4) provide a process by which the ISO will select the more efficient or cost effective regulated Public Policy Transmission Project, if any, to satisfy each identified Public Policy Transmission Need for eligibility for cost allocation under the ISO Tariffs; (5) provide a cost allocation methodology for regulated Public Policy Transmission Projects that have been selected by the ISO, and (6) coordinate the ISO's Public Policy Transmission Planning Process with neighboring Control Areas.

### 31.1.6 Interregional Planning Process

The ISO, the Transmission Owners, and Market Participants and other interested parties shall coordinate system planning activities with neighboring planning regions (*i.e.*, the ISO/RTO Regions and adjacent portions of Canada). The Interregional Planning Protocol includes a description of the committee structure, processes, and procedures through which system planning activities are openly and transparently coordinated by the ISO/RTO Regions. The objective of the interregional planning process is to contribute to the on-going reliability and the enhanced operational and economic performance of the ISO/RTO Regions through: (1) exchange of relevant data and information; (2) coordination of procedures to evaluate certain interconnection

and transmission service requests; (3) periodic comprehensive interregional assessments; (4) identification and evaluation of potential Interregional Transmission Projects that can address regional needs in a manner that may be more efficient or cost-effective than separate regional solutions, in accordance with the requirements of Order No. 1000; (5) allocation of costs among the ISO/RTO Regions of Interregional Transmission Projects, identified in accordance with the Interregional Planning Protocol and approved by each region, pursuant to the cost allocation methodology set forth in Section 31.5.7 herein. The planning activities of the ISO/RTO Regions shall be conducted consistent with the planning criteria of each ISO/RTO Region's regional reliability organization(s) as well as the relevant local reliability entities. The ISO/RTO Regions shall periodically produce a Northeastern Coordinated System Plan that integrates the system plans of all of the ISO/RTO Regions.

### 31.1.7 Enrollment in the ISO's Transmission Planning Region

For purposes of any matter addressed by this Attachment Y, participation in the ESPWG, IPTF and TPAS shall be open to any interested entity, irrespective of whether that entity has become a Party to the ISO Agreement. Any entity may enroll in the ISO's transmission planning region in order to fully participate in the ISO's governance process by becoming a Party to the ISO Agreement, as set forth in Section 2.02 of the ISO Agreement. An owner of transmission in New York State may become a Transmission Owner by: (i) satisfying the definition of a Transmission Owner in Article 1 of the ISO Agreement and (ii) executing the ISO/TO Agreement or an agreement with the ISO under terms comparable to the ISO/TO Agreement and turning over operational control of its transmission facilities to the ISO. As of October 15, 2013, the Transmission Owners are: (1) Central Hudson Gas & Electric Corporation, (2) Consolidated Edison Company of New York, Inc., (3) New York State Electric & Gas Corporation, (4)

Niagara Mohawk Power Corporation d/b/a National Grid, (5) Orange and Rockland Utilities, Inc., (6) Rochester Gas and Electric Corporation, (7) the Power Authority of the State of New York, and (8) Long Island Lighting Company d/b/a LIPA.

### 31.1.8 ISO Implementation and Administration

31.1.8.1 The ISO shall adopt procedures for the implementation and administration of the CSPP set forth in this Attachment Y and the Interregional Planning Protocol, and shall revise those procedures as and when necessary. Such procedures will be incorporated in the ISO's manuals. The ISO Procedures shall provide for the open and transparent coordination of the CSPP to allow Market Participants and all other interested parties to have a meaningful opportunity to participate in each stage of the CSPP through the meetings conducted in accordance with the ISO system of collaborative governance. Confidential Information and Critical Energy Infrastructure Information exchanged through the CSPP shall be subject to the protections for such information contained in the ISO's tariffs and procedures, including this Attachment Y and Attachment F of the ISO OATT.

31.1.8.2 The ISO Procedures shall include a schedule for the collection and submission of data and the preparation of models to be used in the studies contemplated under this tariff. That schedule shall provide for a rolling two-year cycle of studies and reports conducted in each of the ISO planning processes (reliability, economic and public policy) as part of the Comprehensive System Planning Process. Each cycle commences with the LTPP providing input into the reliability planning process. The CARIS study under Section 31.3 of this

Attachment Y will commence upon completion of the viability and sufficiency analysis performed pursuant to Section 31.2.5.7, as part of the CRP process. The Public Policy Transmission Planning Process will to the extent practicable run in parallel with the reliability planning process, provided that the NYPSC's issuance of a written statement pursuant to Section 31.4.2.1 will occur after the draft RNA study results are posted. If the CRP cannot be completed within a two-year cycle, the ISO will notify stakeholders and provide an estimated completion date and an explanation of the reasons the additional time is required. As further detailed in Sections 31.2, 31.3, 31.4, and 31.5, the interregional planning process shall be conducted in parallel with the reliability planning process, the economic planning process, and the Public Policy Transmission Planning Process to identify and evaluate Interregional Transmission Projects that may more efficiently or cost-effectively meet the needs of the region than a regional transmission project.

31.1.8.3 The ISO Procedures shall be designed to allow the coordination of the ISO's planning activities with those of the ISO/RTO Regions, NERC, NPCC, the NYSRC, and other regional reliability organizations so as to develop consistency of the models, databases, and assumptions utilized in making reliability and economic determinations.

31.1.8.4 The ISO Procedures shall facilitate the timely identification and resolution of all substantive and procedural disputes that arise out of the CSPP. Any party participating in the CSPP and having a dispute arising out of the CSPP may seek to have its dispute resolved in accordance with ISO governance procedures during the course of the CSPP. If the party's dispute is not resolved in this manner as a

part of the plan development process, the party may invoke formal dispute resolution procedures administered by the ISO that are the same as those available to Transmission Customers under Section 11 of the ISO Market Administration and Control Area Services Tariff. Disputes arising out of the LTPP shall be addressed by the LTP DRP set forth in Section 31.2.1.4 of this Attachment Y.

31.1.8.5 Except for those cases where the ISO OATT provides that an individual customer shall be responsible for the cost, or a specified share of the cost, of an individually requested study related to interconnection or to system expansion or to congestion and resource integration, the study costs incurred by the ISO as a result of its administration of the CSPP will be recovered from all customers through and in accordance with Rate Schedule 1 of the ISO OATT.

31.1.8.6 The ISO shall make reasonable efforts to meet all deadlines provided in this Attachment Y; *provided, however*, that the ISO must meet all deadlines set forth in a development agreement entered into pursuant to this Attachment Y in accordance with the terms of that agreement. If the ISO cannot meet a deadline set forth in this Attachment Y and an extension of that deadline will not result in a reliability violation, the ISO may extend the deadline, provided that it shall notify Market Participants and other interested parties, explain the reason for the failure to meet the deadline, and provide an estimated time by which it will complete the applicable action.

31.1.8.7 With the exception of the deadlines set forth in a development agreement entered into pursuant to this Attachment Y, the ISO may extend, at its discretion, a deadline applicable to another party under this Attachment Y for a reasonable

period of time if the extension: (i) is applied equally to all parties that are required to meet the deadline, and (ii) will not result in a reliability violation.

## 31.2 Reliability Planning Process

### 31.2.1 Local Transmission Owner Planning Process

#### 31.2.1.1 Scope

##### 31.2.1.1.1 Criteria, Assumptions and Data

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

##### 31.2.1.1.2 Consideration of Transmission Needs Driven by Public Policy Requirements

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

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

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

#### 31.2.1.1.2.2 Determination of Local Transmission Needs Driven by Public Policy Requirements

As part of its LTP process pursuant to Section 31.2.1.2 below, each Transmission Owner will consider whether there is a transmission need on its local system that is being driven by a Public Policy Requirement for which a local transmission solution should be evaluated, including needs proposed by market participants and other interested parties. A market participant or other interested party proposing a transmission need on a Transmission Owner's local system driven by a Public Policy Requirement shall submit its proposal to the ISO and the relevant Transmission Owner, and will identify the specific Public Policy Requirement that is driving the proposed transmission need and an explanation of why a local transmission upgrade is necessary to implement the Public Policy Requirement. Any proposed local system transmission need will be posted on the ISO website. The ISO will transmit proposed transmission needs on a Transmission Owner's local system driven by Public Policy Requirements to the NYDPS, with a request that the NYDPS review the proposals and provide the relevant Transmission Owner with input to assist the Transmission Owner in its determination. The Transmission Owner, after considering the input provided by the NYDPS and any information provided by a market participant or other party, will determine whether there are transmission needs driven by Public Policy Requirements for which local transmission solutions should be evaluated. The Transmission Owner will post on its website a list of the transmission needs driven by Public Policy Requirements for which local transmission solutions should be evaluated, with an explanation of why the Transmission Owner identified those transmission needs and declined to identify other proposed transmission needs.

#### 31.2.1.1.2.3 Evaluation of Proposed Local Transmission Solutions

In evaluating potential transmission solutions, if any, the Transmission Owner will give consideration to the objectives of the Public Policy Requirement driving the need for a local transmission solution. The Transmission Owner will evaluate solutions to identified transmission needs, including transmission solutions proposed by market participants and other parties for inclusion in its LTP. The Transmission Owner, in consultation with the NYDPS, will evaluate proposed transmission solutions on its local system to determine the more efficient or cost-effective transmission solutions. The Transmission Owner will consider the relative costs and benefits of proposed transmission solutions and their impact on the Transmission Owner's transmission system and its customers. Any local transmission solution identified by the Transmission Owner through the LTP process will be reviewed with stakeholders as part of each Transmission Owner's regular LTP process and will be included in the Transmission Owner's subsequent LTP. In conducting its evaluation the Transmission Owner will use criteria that are relevant to the Public Policy Requirement driving the transmission need, which may include its published local planning criteria and assumptions.

### 31.2.1.2 Process Timeline

31.2.1.2.1 Each Transmission Owner, in accordance with a schedule set forth in the ISO Procedures, will post its current LTP on its website for review and comment by interested parties sufficiently in advance of the time for submission to the ISO for input to its RNA so as to allow adequate time for stakeholder review and comment. Each LTP will include:

- identification of the planning horizon covered by the LTP,
- data and models used,

- reliability needs, needs driven by Public Policy Requirements, and other needs addressed,
- potential solutions under consideration, and,
- a description of the transmission facilities covered by the plan.

31.2.1.2.2 To the extent the current LTP utilizes data or inputs, related to the ISO's planning process, not already reported by the ISO in Form 715 and referenced on its website, any such data will be provided to the ISO at the time each Transmission Owner posts criteria and planning assumptions in accordance with Section 31.2.1.1 and will be posted by the ISO on its website subject to any confidentiality or Critical Energy Infrastructure Information restrictions or requirements.

31.2.1.2.3 Each planning cycle, the ISO shall hold one or more stakeholder meetings of the ESPWG and TPAS at which each Transmission Owner's current LTP will be discussed. Such meetings will be held either at the Transmission Owner's Transmission District, or at an ISO location. The ISO shall post notice of the meeting and shall disclose the agenda and any other material distributed prior to the meeting.

31.2.1.2.4 Interested parties may submit written comments to a Transmission Owner with respect to its current LTP within thirty days after the meeting. Each Transmission Owner shall list on its website, as part of its LTP, the person and/or location to which comments should be sent by interested parties. All comments will be posted on the ISO website. Each Transmission Owner will consider comments received in developing any modifications to its LTP. Any such modification will be explained in its current LTP posted on its website pursuant to

Section 31.2.1.2.2 above and discussed at the next meeting held pursuant to Section 31.2.1.2.3 above.

31.2.1.2.5 Each planning cycle, each Transmission Owner will submit the finalized portions of its current LTP to the ISO as contemplated in Section 31.2.2.4.2 below for timely inclusion in the RNA.

#### 31.2.1.3 ISO Evaluation of Transmission Owner Local Transmission Plans in Relation to Regional and Local Transmission Needs

The ISO will review the Transmission Owner LTPs as they relate to the BPTFs as set forth in Section 31.2.2.4.2. The ISO will also evaluate whether a regional transmission solution – including, but not limited to, regional transmission solutions proposed by Developers pursuant to this Attachment Y – could satisfy an identified regional transmission need on the BPTFs that impacts more than one Transmission District more efficiently or more cost effectively than a local transmission solution identified in a Transmission Owner's LTP in accordance with Section 31.2.6.4.2 for the satisfaction of a regional Reliability Need, Section 31.3.1.3.6 for the reduction of congestion identified in CARIS, or Section 31.4.7.2 for the satisfaction of a Public Policy Transmission Need. The ISO will report the results of its evaluation solely for informational purposes in the relevant ISO planning report prepared under this Attachment Y, and the Transmission Owners shall not be required to revise their LTPs based on the results of the ISO's evaluation.

#### 31.2.1.4 LTP Dispute Resolution Process

##### 31.2.1.4.1 Disputes Related to the LTPP; Objective; Notice

Disputes related to the LTPP are subject to the DRP. The objective of the DRP is to assist parties having disputes in communicating effectively and resolving disputes as

expeditiously as possible. Within fifteen (15) calendar days of the presentation by a Transmission Owner of its LTP to the ESPWG and TPAS, a party with a dispute shall notify in writing the Affected TO, the ISO, the ESPWG and TPAS of its intention to utilize the DRP. The notice shall identify the specific issue in dispute and describe in sufficient detail the nature of the dispute.

**31.2.1.4.2 Review by the ESPWG/TPAS**

The issue raised by a party with a dispute shall be reviewed and discussed at a joint meeting of the ESPWG and the TPAS in an effort to resolve the dispute. The party with a dispute and the Affected TO shall have an opportunity to present information concerning the issue in dispute to the ESPWG and the TPAS.

**31.2.1.4.3 Information Discussions**

To the extent the ESPWG and the TPAS are unable to resolve the dispute, the dispute will be subject to good faith informal discussions between the party with a dispute and the Affected TO. Each of those parties will designate a senior representative authorized to enter into informal discussions and to resolve the dispute. The parties to the dispute shall make a good faith effort to resolve the dispute through informal discussions as promptly as practicable.

**31.2.1.4.4 Alternative Dispute Resolution**

In the event that the parties to the dispute are unable to resolve the dispute through informal discussions within sixty (60) days, or such other period as the parties may agree upon, the parties may, by mutual agreement, submit the dispute to mediation or any other form of alternative dispute resolution. The parties shall attempt in good faith to resolve the dispute in accordance with a mutually agreed upon schedule but in no event may the schedule extend

beyond ninety (90) days from the date on which the parties agreed to submit the dispute to alternative dispute resolution.

#### 31.2.1.4.5 Notice of Results of Dispute Resolution

The Affected TO shall notify the ISO and ESPWG and TPAS of the results of the DRP and update its LTP to the extent necessary. The ISO shall use in its planning process the LTP provided by the Affected TO.

#### 31.2.1.4.6 Rights Under the Federal Power Act

Nothing in the DRP shall affect the rights of any party to file a complaint with the Commission under relevant provisions of the FPA.

#### 31.2.1.4.7 Confidentiality

All information disclosed in the course of the DRP shall be subject to the same protections accorded to confidential information and CEII by the ISO under its confidentiality and CEII policies.

### 31.2.2 Reliability Needs Assessment

#### 31.2.2.1 General

The ISO shall prepare and publish the RNA as described below. The RNA will identify Reliability Needs. The ISO shall also designate in the RNA the Responsible Transmission Owner with respect to each Reliability Need.

#### 31.2.2.2 Interested Party Participation in the Development of the RNA

The ISO shall develop the RNA in consultation with Market Participants and all other interested parties. TPAS will have responsibility consistent with ISO Procedures for review of the ISO's reliability analyses. ESPWG will have responsibility consistent with ISO Procedures

for providing commercial input and assumptions to be used in the development of reliability assessment scenarios provided under Section 31.2.2.5, and in the reporting and analysis of historic congestion costs. Coordination and communication will be established and maintained between these two groups and ISO staff to allow Market Participants and other interested parties to participate in a meaningful way during each stage of the CSPP. The ISO staff shall report any majority and minority views of these collaborative governance work groups when it submits the RNA to the Operating Committee for a vote, as provided below.

**31.2.2.3 Preparation of the Reliability Needs Assessment**

31.2.2.3.1 The ISO shall evaluate bulk power system needs in the RNA over the Study Period.

31.2.2.3.2 The starting point for the development of the RNA Base Case will be the system as defined for the FERC Form No. 715 Base Case. The ISO shall develop this system representation to be used for its evaluations of the Study Period by primarily using: (1) the most recent NYISO Load and Capacity Data Report published by the ISO on its web site; (2) the most recent versions of ISO reliability analyses and assessments provided for or published by NERC, NPCC, NYSRC, and neighboring Control Areas; (3) information reported by neighboring Control Areas such as power flow data, forecasted load, significant new or modified generation and transmission facilities, and anticipated system conditions that the ISO determines may impact the BPTFs; and (4) data submitted pursuant to paragraph 31.2.2.4 below; *provided, however*, the ISO shall not include in the RNA Base Case an RMR Generator; *provided, further*, the ISO may include a non-RMR Generator Gap Solution in the RNA Base Case as appropriate. The

details of the development of the RNA Base Case are contained in the ISO Procedures. The RNA Base Case shall also include Interregional Transmission Projects that have been approved by the NYPSC transmission siting process and meet the base case inclusion requirements in the ISO Procedures.

31.2.2.3.3 The ISO shall assess the RNA Base Case to determine whether the BPTFs meet all Reliability Criteria for both resource and transmission adequacy in each year, and report the results of its evaluation in the RNA. Transmission analyses will include thermal, voltage, short circuit, and stability studies. Then, if any Reliability Criteria are not met in any year, the ISO shall perform additional analyses to determine whether additional resources and/or transmission capacity expansion are needed to meet those requirements, and to determine the Target Year of need for those additional resources and/or transmission. A short circuit assessment will be performed for the tenth year of the Study Period. The study will not seek to identify specific additional facilities. Reliability Needs will be defined in terms of total deficiencies relative to Reliability Criteria and not necessarily in terms of specific facilities.

**31.2.2.4 Planning Participant Data Input**

31.2.2.4.1 At the ISO's request, Market Participants, Developers, and other parties shall provide, in accordance with the schedule set forth in the ISO Procedures, the data necessary for the development of the RNA. This data will include but not be limited to (1) existing and planned additions to the New York State Transmission System (to be provided by Transmission Owners and municipal electric utilities); (2) proposals for merchant transmission facilities (to be provided by merchant

Developers); (3) generation additions and retirements (to be provided by generator owners and Developers); (4) demand response programs (to be provided by demand response providers); and (5) any long-term firm transmission requests made to the ISO.

31.2.2.4.2 The Transmission Owners shall submit their current LTPs referenced in Section 31.1.3 and Section 31.2.1 to the ISO. The Transmission Owners and the ISO will coordinate with each other in reviewing the LTPs. The ISO will review the Transmission Owners' LTPs, as they relate to BPTFs, to determine whether they will meet reliability needs identified in the LTPs, recommend an alternate means to resolve the local needs from a regional perspective pursuant to Section 31.2.6.4, and indicate if it is not in agreement with a Transmission Owner's proposed additions. The ISO shall report its determinations under this section in the RNA and in the CRP.

31.2.2.4.3 All data received from Market Participants, Developers, and other parties shall be considered in the development of the system representation for the Study Period in accordance with the ISO Procedures.

**31.2.2.5 Reliability Scenario Development**

The ISO, in consultation with the ESPWG and TPAS, shall develop reliability scenarios addressing the Study Period. Variables for consideration in the development of these reliability scenarios include but are not limited to: load forecast uncertainty, fuel prices and availability, new resources, retirements, transmission network topology, and limitations imposed by proposed environmental or other legislation.

#### 31.2.2.6 Evaluation of Reliability Scenarios

The ISO will conduct additional reliability analyses for the reliability scenarios developed pursuant to paragraph 31.2.2.5. These evaluations will test the robustness of the needs assessment studies conducted under paragraphs 31.2.2.3. This evaluation will only identify conditions under which Reliability Criteria may not be met. It will not identify or propose additional Reliability Needs. In addition, the ISO will perform appropriate sensitivity studies to determine whether Reliability Needs previously identified can be mitigated through alternate system configurations or operational modes. The Reliability Needs may increase in some reliability scenarios and may decrease, or even be eliminated, in others. The ISO shall report the results of these evaluations in the RNA.

#### 31.2.2.7 Consequences for Other Regions

The ISO will coordinate with the ISO/RTO Regions to identify the consequences of the reliability transmission projects on such ISO/RTO Regions using the respective planning criteria of such ISO/RTO Regions. The ISO shall report the results in the CRP. The ISO shall not bear the costs of required upgrades in another region.

#### 31.2.2.8 Reliability Needs Assessment Report Preparation

Once all the analyses described above have been completed, ISO staff will prepare a draft of the RNA including discussion of its assumptions, Reliability Criteria, and results of the analyses and, if necessary, designate the Responsible Transmission Owner. One or more compensatory MW/ Load adjustment scenarios will be developed by the ISO as a guide to the development of proposed solutions to meet the identified Reliability Need.

### 31.2.3 RNA Review Process

#### 31.2.3.1 Collaborative Governance Process

The draft RNA shall be submitted to both TPAS and the ESPWG for review and comment. The ISO shall make available to any interested party sufficient information to replicate the results of the draft RNA. The information made available will be electronically masked and made available pursuant to a process that the ISO reasonably determines is necessary to prevent the disclosure of any Confidential Information or Critical Energy Infrastructure Information contained in the information made available. Market Participants and other interested parties may submit at any time optional suggestions for changes to ISO rules or procedures which could result in the identification of additional resources or market alternatives suitable for meeting Reliability Needs. Following completion of the TPAS and ESPWG review, the draft RNA reflecting the revisions resulting from the TPAS and ESPWG review, shall be forwarded to the Operating Committee for discussion and action. The ISO shall notify the Business Issues Committee of the date of the Operating Committee meeting at which the draft RNA is to be presented. Following the Operating Committee vote, the draft RNA will be transmitted to the Management Committee for discussion and action.

#### 31.2.3.2 Board Action

Following the Management Committee vote, the draft RNA, with working group, Operating Committee, and Management Committee input, will be forwarded to the ISO Board for review and action. Concurrently, the draft RNA will be provided to the Market Monitoring Unit for its review and consideration of whether market rules changes are necessary to address an identified failure, if any, in one of the ISO's competitive markets. The Board may approve the RNA as submitted, or propose modifications on its own motion. If any changes are proposed

by the Board, the revised RNA shall be returned to the Management Committee for comment. The Board shall not make a final determination on a revised RNA until it has reviewed the Management Committee comments. Upon approval by the Board, the ISO shall issue the final RNA to the marketplace by posting it on its web site.

The responsibilities of the Market Monitoring Unit that are addressed in the above section of this Attachment are also addressed in Section 30.4.6.8.2 of the Market Monitoring Plan, Attachment O to the ISO Services Tariff.

#### 31.2.3.3 Needs Assessment Disputes

Notwithstanding any provision to the contrary in this Attachment, the ISO OATT, or the NYISO Services Tariff, in the event that a Market Participant raises a dispute solely within the NYPSC's jurisdiction relating to the final conclusions or recommendations of the RNA, a Market Participant may refer such dispute to the NYPSC for resolution. The NYPSC's final determination shall be binding, subject only to judicial review in the courts of the State of New York pursuant to Article 78 of the NYCPLR.

#### 31.2.3.4 Public Information Sessions

In order to provide ample exposure for the marketplace to understand the identified Reliability Needs, the ISO will provide various opportunities for Market Participants and other potentially interested parties to discuss the final RNA. Such opportunities may include presentations at various ISO Market Participant committees, focused discussions with various industry sectors, and/or presentations in public venues.

### 31.2.4 Development of Solutions to Reliability Needs

#### 31.2.4.1 Eligibility and Qualification Criteria for Developers and Projects

For purposes of fulfilling the requirements of the Developer qualification criteria in this Section 31.2.4.1 and its subsections, the term "Developer" includes Affiliates, as that term is defined in Section 2 of the ISO Services Tariff and Section 1 of the ISO OATT. To the extent that a Developer relies on Affiliate(s) to satisfy any or all of the qualification criteria set forth in Section 31.2.4.1.1.1, the Affiliate(s) shall provide to the ISO: (i) the information required in Section 31.2.4.1.1.1 to demonstrate its capability to satisfy the applicable qualification criteria, and (ii) a notarized officer's certificate, signed by an authorized officer of the Affiliate with signatory authority, in a form acceptable to the ISO, certifying that the Affiliate will participate in the Developer's project in the manner described by the Developer and will abide by the requirements set forth in this Attachment Y, the ISO Tariffs, and ISO Procedures related and applicable to the Affiliate's participation.

##### 31.2.4.1.1 Developer Qualification and Timing

The ISO shall provide each Developer with an opportunity to demonstrate that it has or can draw upon the financial resources, technical expertise, and experience needed to finance, develop, construct, operate and maintain a transmission project to meet identified Reliability Needs. The ISO shall consider the qualifications of each Developer in an evenhanded and non-discriminatory manner, treating Transmission Owners and Other Developers alike.

###### 31.2.4.1.1.1 Developer Qualification Criteria

The ISO shall make a determination on the qualification of a Developer to propose to develop a transmission project as a solution to an identified Reliability Need based on the following criteria:

31.2.4.1.1.1.1 The technical and engineering qualifications and experience of the Developer relevant to the development, construction, operation and maintenance of a transmission facility, including evidence of the Developer's demonstrated capability to adhere to standardized construction, maintenance, and operating practices and to contract with third parties to develop, construct, maintain, and/or operate transmission facilities;

31.2.4.1.1.1.2 The current and expected capabilities of the Developer to develop and construct a transmission facility and to operate and maintain it for the life of the facility. If the Developer has previously developed, constructed, maintained or operated transmission facilities, the Developer shall provide the ISO a description of the transmission facilities (not to exceed ten) that the Developer has previously developed, constructed, maintained or operated and the status of those facilities, including whether the construction was completed, whether the facility entered into commercial operations, whether the facility has been suspended or terminated for any reason, and evidence demonstrating the ability of the Developer to address and timely remedy any operational failure of the facilities; and

31.2.4.1.1.1.3 The Developer's current and expected capability to finance, or its experience in arranging financing for, transmission facilities. For purposes of the ISO's determination, the Developer shall provide the ISO:

(1) evidence of its demonstrated experience financing or arranging financing for transmission facilities, if any, including a description of such projects (not to exceed ten) over the previous ten years, the capital costs and financial structure of such projects, a description of any financing obtained for these projects through

rates approved by the Commission or a state regulatory agency, the financing closing date of such projects, and whether any of the projects are in default;

(2) its audited annual financial statements from the most recent three years and its most recent quarterly financial statement, or equivalent information;

(3) its credit rating from Moody's Investor Services, Standard & Poor's, or Fitch, or equivalent information, if available;

(4) a description of any prior bankruptcy declarations, material defaults, dissolution, merger or acquisition by the Developer or its predecessors or subsidiaries occurring within the previous five years; and

(5) such other evidence that demonstrates its current and expected capability to finance a project to solve a Reliability Need.

31.2.4.1.1.1.4 A detailed plan describing how the Developer – in the absence of previous experience financing, developing, constructing, operating, or maintaining transmission facilities – will finance, develop, construct, operate, and maintain a transmission facility, including the financial, technical, and engineering qualifications and experience and capabilities of any third parties with which it will contract for these purposes.

**31.2.4.1.1.2 Developer Qualification Determination**

Any Developer seeking to become qualified may submit the required information, or update any previously submitted information, at any time. The ISO shall treat on a confidential basis in accordance with the requirements of its Code of Conduct in Attachment F of the ISO OATT any non-public financial qualification information that is submitted to the ISO by the Developer under Section 31.2.4.1.1.1.3 and is designated by the Developer as "Confidential

Information." The ISO shall within 15 days of a Developer's submittal, notify the Developer if the information is incomplete. If the submittal is deemed incomplete, the Developer shall submit the additional information within 30 days of the ISO's request. The ISO shall notify the Developer of its qualification status within 30 days of receiving all necessary information. A Developer shall retain its qualification status for a three-year period following the notification date; *provided, however*, that the ISO may revoke this status if it determines that there has been a material change in the Developer's qualifications and the Developer no longer meets the qualification requirements. A Developer that has been qualified shall inform the ISO within thirty days of any material change to the information it provided regarding its qualifications and shall submit to the ISO each year its most recent audited annual financial statement when available. At the conclusion of the three-year period or following the ISO's revocation of a Developer's qualification status, the Developer may re-apply for a qualification status under this section.

Any Developer determined by the ISO to be qualified under this section shall be eligible to propose a regulated transmission project as a solution to an identified Reliability Need and shall be eligible to use the cost allocation and cost recovery mechanism for regulated transmission projects set forth in Section 31.5 of this Attachment Y and Rate Schedule 10, Section 6.10, of the ISO OATT for any approved project.

#### 31.2.4.2 Interregional Transmission Projects

Interregional Transmission Projects may be proposed under Section 31.2.5.1 of this Attachment Y as regulated backstop solutions, alternative regulated solutions, or market-based solutions, in response to a request by the ISO for solutions to a Reliability Need under the relevant provisions of Section 31.2.4. Interregional Transmission Projects proposed as regulated

backstop solutions, alternative regulated solutions or market-based solutions shall be: (i) evaluated by the ISO in accordance with the applicable requirements of the reliability planning process of this Attachment Y, and (ii) jointly evaluated by the ISO and the relevant adjacent transmission planning region(s) in accordance with Section 7.3 of the Interregional Planning Protocol.

#### 31.2.4.3 Regulated Backstop Solutions

31.2.4.3.1 When a Reliability Need is identified in any RNA issued under this tariff, the ISO shall request and the Responsible Transmission Owner shall provide to the ISO, as set forth in Section 31.2.5 below, a proposal for a regulated solution or combination of solutions that shall serve as a backstop to meet the Reliability Need if requested by the ISO due to the lack of sufficient viable market-based solutions to meet such Reliability Needs identified for the Study Period. The Responsible Transmission Owner shall be eligible to recover its costs for developing its proposal and seeking necessary approvals under Rate Schedule 10 of the ISO OATT. Regulated backstop solutions may include generation, transmission, or demand side resources. Such proposals may include reasonable alternatives that would effectively address the Reliability Need; provided however, the Responsible Transmission Owner's obligation to propose and implement regulated backstop solutions under this tariff is limited to regulated transmission solutions. Prior to providing its response to the RNA, each Responsible Transmission Owner will present for discussion at the ESPWG and TPAS any updates in its LTP that impact a Reliability Need identified in the RNA. The ISO will present at the ESPWG and TPAS any updates to its

determination under Section 31.2.2.4.2 with respect to the Transmission Owners' LTPs. Should more than one regulated backstop solution be proposed by a Responsible Transmission Owner to address a Reliability Need, it will be the responsibility of that Responsible Transmission Owner to determine which of the regulated backstop solutions will proceed following a finding by the ISO under Section 31.2.8 of this Attachment Y. The determination by the Responsible Transmission Owner will be made prior to the approval of the CRP which precedes the Trigger Date for the regulated backstop solution with the longest lead time. Contemporaneous with the request to the Responsible Transmission Owner, the ISO shall solicit market-based and alternative regulated responses as set forth in Sections 31.2.4.5 and 31.2.4.7, which shall not be a formal RFP process.

**31.2.4.4 Qualifications for Regulated Backstop Solutions**

31.2.4.4.1 The submission of a regulated backstop solution to a Reliability Need for purposes of the ISO's evaluation under Section 31.2.5 of the viability and sufficiency of the proposed solution and the determination of the Trigger Date for the proposed solution shall include, at a minimum, the following details: (1) contact information; (2) the lead time necessary to complete the project, including, if available, the construction windows in which the Responsible Transmission Owner can perform construction and what, if any, outages may be required during these periods; (3) a description of the project, including type, size, and geographic and electrical location, as well as planning and engineering specifications and drawings as appropriate; (4) evidence of a commercially viable

technology, (5) a major milestone schedule; (6) the schedule for obtaining any permits and other certifications, if available; (7) status of ISO interconnection studies and interconnection agreement, if available; and (8) status of equipment availability and procurement, if available.

31.2.4.4.2 The submission of a regulated backstop solution to a Reliability Need for purposes of the ISO's evaluation of the proposed solution for possible selection as the more efficient or cost effective solution to the Reliability Need shall include, at a minimum, the following details: (1) updates to the information required under Section 31.2.4.4.1; (2) the schedule for obtaining required permits and other certifications; (3) a demonstration of Site Control or a schedule for obtaining such control; (4) the status of any contracts (other than an Interconnection Agreement) that are under negotiation or in place, including any contracts with third-party contractors; (5) status of ISO interconnection studies and interconnection agreement; (6) status of equipment availability and procurement; (7) evidence of financing or ability to finance the project; (8) capital cost estimates for the project; (9) a description of permitting or other risks facing the project at the stage of project development, including evidence of the reasonableness of project cost estimates, all based on the information available at the time of the submission; and (10) any other information requested by the ISO.

A Responsible Transmission Owner shall submit the following information to indicate the status of any contracts: (i) copies of all final contracts the ISO determines are relevant to its consideration, or (ii) where one or more contracts are pending, a timeline on the status of discussions and negotiations

with the relevant documents and when the negotiations are expected to be completed. The final contracts shall be submitted to the ISO when available. The ISO shall treat on a confidential basis in accordance with the requirements of its Code of Conduct in Attachment F of the ISO OATT any contract that is submitted to the ISO and is designated by the Responsible Transmission Owner as "Confidential Information."

A Responsible Transmission Owner shall submit the following information to indicate the status of any required permits: (i) copies of all final permits received that the ISO determines are relevant to its consideration, or (ii) where one or more permits are pending, the completed permit application(s) with information on what additional actions must be taken to meet the permit requirements and a timeline providing the expected timing for finalization and receipt of the final permit(s). The final permits shall be submitted to the ISO when available.

A Responsible Transmission Owner shall submit the following information, as appropriate, to indicate evidence of financing by it or any Affiliate upon which it is relying for financing: (i) evidence of self-financing or project financing through approved rates or the ability to do so, (ii) copies of all loan commitment letter(s) and signed financing contract(s), or (iii) where such financing is pending, the status of the application for any relevant financing, including a timeline providing the status of discussions and negotiations of relevant documents and when the negotiations are expected to be completed. The final contracts or approved rates shall be submitted to the ISO when available.

31.2.4.4.3 If the regulated backstop solution does not meet the Reliability Needs , the ISO will provide sufficient information to the Responsible Transmission Owner to determine how the regulated backstop should be modified to meet the identified Reliability Needs. The Responsible Transmission Owner will make necessary changes to its proposed regulated backstop solution to address reliability deficiencies identified by the ISO, and submit a revised proposal to the ISO for review and approval.

**31.2.4.5 Market-Based Responses**

At the same time that a proposal for a regulated backstop solution is requested from the Responsible Transmission Owner under Section 31.2.4.3, the ISO shall also request market-based responses from the market place. Subject to the execution of appropriately drawn confidentiality agreements and the Commission's standards of conduct, the ISO and the appropriate Transmission Owner or Transmission Owners shall provide any party who wishes to develop such a response access to the data that is necessary to develop its response. Such data shall only be used for the purposes of preparing a market-based response to a Reliability Need under this section. Such responses will be open on a comparable basis to all resources, including generation, demand response providers, and merchant transmission Developers.

**31.2.4.6 Qualifications for a Valid Market-Based Response**

The submission of a proposed market-based solution must include, at a minimum: (1) contact information; (2) the lead time necessary to complete the project, including, if available, the construction windows in which the Developer can perform construction and what, if any, outages may be required during these periods; (3) a description of the project, including type, size, and geographic and electrical location, as well as planning and engineering

specifications and drawings as appropriate; (4) evidence of a commercially viable technology; (5) a major milestone schedule; (6) a schedule for obtaining any required permits and other certifications; (7) a demonstration of Site Control or a schedule for obtaining Site Control; (8) the status of any contracts (other than an Interconnection Agreement) that are under negotiation or in place; (9) the status of ISO interconnection studies and interconnection agreement; (10) the status of equipment availability and procurement; (11) evidence of financing or ability to finance the project; and (12) any other information requested by the ISO.

A Developer shall submit the following information to indicate the status of any contracts: (i) copies of all final contracts the ISO determines are relevant to its consideration, or (ii) where one or more contracts are pending, a timeline on the status of discussions and negotiations with the relevant documents and when the negotiations are expected to be completed. The final contracts shall be submitted to the ISO when available. The ISO shall treat on a confidential basis in accordance with the requirements of its Code of Conduct in Attachment F of the ISO OATT any contract that is submitted to the ISO and is designated by the Developer as "Confidential Information."

A Developer shall submit the following information to indicate the status of any required permits: (i) copies of all final permits received that the ISO determines are relevant to its consideration, or (ii) where one or more permits are pending, the completed permit application(s) with information on what additional actions must be taken to meet the permit requirements and a timeline providing the expected timing for finalization and receipt of the final permit(s). The final permits shall be submitted to the ISO when available.

A Developer shall submit the following information, as appropriate, to indicate evidence of financing by it or any Affiliate upon which it is relying for financing: (i) copies of all loan

commitment letter(s) and signed financing contract(s), or (ii) where such financing is pending, the status of the application for any relevant financing, including a timeline providing the status of discussions and negotiations of relevant documents and when the negotiations are expected to be completed. The final contracts shall be submitted to the ISO when available.

Failure to provide any data requested by the ISO within the timeframe set forth in Section 31.2.5.1 of this Attachment Y will result in the rejection of the proposed market-based solution from further consideration during that planning cycle.

**31.2.4.7 Alternative Regulated Responses**

31.2.4.7.1 The ISO will request alternative regulated responses to Reliability Needs at the same time that it requests market-based responses and regulated backstop solutions. Such proposals may include reasonable alternatives that would effectively address the identified Reliability Need.

31.2.4.7.2 In response to the ISO's request, Other Developers may develop alternative regulated proposals for generation, demand side alternatives, and/or other solutions to address a Reliability Need and submit such proposals to the ISO. Transmission Owners, at their option, may submit additional proposals for regulated solutions to the ISO. Transmission Owners and Other Developers may submit such proposals to the NYDPS for review at any time. Subject to the execution of appropriately drawn confidentiality agreements and the Commission's standards of conduct, the ISO and the appropriate Transmission Owner(s) shall provide Other Developers access to the data that is needed to develop their proposals. Such data shall be used only for purposes of preparing an alternative regulated proposal in response to a Reliability Need.

### 31.2.4.8 Qualifications for Alternative Regulated Solutions

31.2.4.8.1 The submission of an alternative regulated solution to a Reliability Need for purposes of the ISO's evaluation under Section 31.2.5 of the viability and sufficiency of the proposed solution and the determination of the Trigger Date for the proposed solution shall include, at a minimum, the following details: (1) contact information; (2) the lead time necessary to complete the project, including, if available, the construction windows in which the Other Developer or Transmission Owner can perform construction and what, if any, outages may be required during these periods; (3) a description of the project, including type, size, and geographic and electrical location, as well as planning and engineering specifications and drawings as appropriate; (4) evidence of a commercially viable technology; (5) a major milestone schedule; (6) the schedule for obtaining any permits and other certifications, if available; (7) status of ISO interconnection studies and interconnection agreement, if available; and (8) status of equipment availability and procurement, if available.

31.2.4.8.2 The submission of a proposed alternative regulated solution to a Reliability Need for purposes of the ISO's evaluation of the proposed solution for possible selection as the more efficient or cost effective solution for the Reliability Need must include, at a minimum: (1) updates to the information required under Section 31.2.4.8.1; (2) a demonstration of Site Control or a schedule for obtaining Site Control; (3) the status of any contracts (other than an Interconnection Agreement) that are under negotiation or in place, including any contracts with third-party contractors; (4) the status of any interconnection studies and interconnection agreement; (5) the schedule for obtaining any required

permits and other certifications; (6) the status of equipment availability and procurement; (7) evidence of financing or ability to finance the project; (8) capital cost estimates for the project; (9) a description of permitting or other risks facing the project at the stage of project development, including evidence of the reasonableness of project cost estimates, all based on the information available at the time of the submission; and (10) any other information requested by the ISO.

An Other Developer or Transmission Owner shall submit the following information to indicate the status of any contracts: (i) copies of all final contracts the ISO determines are relevant to its consideration, or (ii) where one or more contracts are pending, a timeline on the status of discussions and negotiations with the relevant documents and when the negotiations are expected to be completed. The final contracts shall be submitted to the ISO when available. The ISO shall treat on a confidential basis in accordance with the requirements of its Code of Conduct in Attachment F of the ISO OATT any contract that is submitted to the ISO and is designated by the Other Developer or Transmission Owner as "Confidential Information."

An Other Developer or Transmission Owner shall submit the following information to indicate the status of any required permits: (i) copies of all final permits received that the ISO determines are relevant to its consideration, or (ii) where one or more permits are pending, the completed permit application(s) with information on what additional actions must be taken to meet the permit requirements and a timeline providing the expected timing for finalization and

receipt of the final permit(s). The final permits shall be submitted to the ISO when available.

An Other Developer or Transmission Owner shall submit the following information, as appropriate, to indicate evidence of financing by it or any Affiliate upon which it is relying for financing: (i) evidence of self-financing or project financing through approved rates or the ability to do so, (ii) copies of all loan commitment letter(s) and signed financing contract(s), or (iii) where such financing is pending, the status of the application for any relevant financing, including a timeline providing the status of discussions and negotiations of relevant documents and when the negotiations are expected to be completed. The final contracts or approved rates shall be submitted to the ISO when available.

31.2.4.8.3 Failure to provide any data requested by the ISO within the timeframe provided in Sections 31.2.5.1 and 31.2.6.1 of this Attachment Y will result in the rejection of the proposed alternative regulated solution from further consideration during that planning cycle. A proponent of a proposed alternative regulated solution must notify the ISO immediately of any material change in status of a proposed alternative regulated solution. For purposes of this provision, a material change includes, but is not limited to, a change in the financial viability of the developer, a change in the siting status of the project, or a change in a major element of the project's development. If the ISO, at any time, learns of a material change in the status of a proposed alternative regulated solution, it may, at that time, make a determination as to the continued viability of the proposed alternative regulated solution.

#### 31.2.4.9 Additional Solutions

Should the ISO determine that it has not received adequate regulated backstop or market-based solutions to satisfy the Reliability Need, the ISO may, in its discretion, solicit additional regulated backstop or market-based solutions. Other Developers or Transmission Owners may submit additional alternative regulated solutions for the ISO's consideration at that time.

### 31.2.5 ISO Evaluation of Viability, Sufficiency, and Trigger Date of Proposed Solutions to Reliability Needs

#### 31.2.5.1 Timing for Submittal of Project Information and Developer Qualification Information and Opportunity to Provide Additional Information

Within 60 days after a request for solutions to a Reliability Need is made by the ISO after completion of the RNA, a Developer proposing a solution to an identified Reliability Need shall submit to the ISO for purposes of its evaluation the project information, as applicable, for: (i) a proposed regulated backstop solution under Section 31.2.4.4.1, (ii) a proposed market-based solution under Section 31.2.4.6, or (iii) a proposed alternative regulated solution under Section 31.2.4.8.1 of this Attachment Y.

Any Developer that the ISO has determined under Section 31.2.4.1.1.2 or as set forth in this Section 31.2.5.1 below to be qualified to propose to develop a project as a transmission solution to an identified Reliability Need may submit the required project information; *provided, however,* that: (i) the Developer shall provide a non-refundable application fee of $10,000 and (ii) based on the actual identified need, the ISO may request that the qualified Developer provide additional Developer qualification information. Any Developer that has not been determined by the ISO to be qualified, but that wants to propose to develop a project, must submit to the ISO the information required for Developer qualification under Section 31.2.4.1.1 within 30 days after a request for solutions is made by the ISO. The ISO shall within 30 days of a Developer's

submittal of its Developer qualification information, notify the Developer if this information is incomplete. The Developer shall submit additional Developer qualification information or project information required by the ISO within 15 days of the ISO's request. A Developer that fails to submit the additional Developer qualification information or the required project information will not be eligible for its project to be considered in that planning cycle.

#### 31.2.5.2 Comparable Evaluation of All Proposed Solutions

The ISO shall evaluate: (i) any proposed market-based solution submitted by a Developer pursuant to Section 31.2.4.5, (ii) any proposed regulated backstop solution submitted by a Responsible Transmission Owner pursuant to Section 31.2.4.3, and (iii) any proposed alternative regulated solution submitted by a Transmission Owner or Other Developer pursuant to Section 31.2.4.7. The ISO will evaluate whether each proposed solution is viable and is sufficient to satisfy the identified Reliability Need by the need date pursuant to Sections 31.2.5.3 and 31.2.5.4. The proposed solutions may include multiple components and resource types. When evaluating proposed solutions to Reliability Needs from any Developer, all resource types – generation, transmission, demand response, or a combination of these resource types – shall be considered on a comparable basis as potential solutions to the Reliability Needs identified. All solutions will be evaluated in the same general time frame.

#### 31.2.5.3 Evaluation of Viability of Proposed Solution

The ISO will determine the viability of a solution – transmission, generation, demand response, or a combination of these resource types – proposed to satisfy a Reliability Need. For purposes of its analysis, the ISO will evaluate whether: (i) the Developer has provided the required Developer qualification data pursuant to Section 31.2.4.1 and the required project information data under Sections 31.2.4.4.1, 31.2.4.6, or 31.2.4.8.1; (ii) the proposed solution is

technically practicable; (iii) the Developer has indicated possession of, or an approach for acquiring, any necessary rights-of-way, property, and facilities that will make the proposal reasonably feasible in the required timeframe; and (iv) the proposed solution can be completed in the required timeframe. If the ISO determines that the proposed solution is not viable and, for regulated solutions, the Developer does not address any identified deficiency pursuant to Section 31.2.5.6, the ISO shall reject the proposed solution from further consideration during that planning cycle.

#### 31.2.5.4 Evaluation of Sufficiency of Proposed Solution

The ISO will perform a comparable analysis of each proposed solution – transmission, generation, demand response, or a combination of these resource types – through the Study Period to identify whether it satisfies the Reliability Need(s). The ISO will evaluate each solution to determine whether the solution proposed by the Developer fully eliminates the Reliability Need(s). If the ISO determines that a proposed regulated solution is not sufficient and the Developer does not address any identified deficiency pursuant to Section 31.2.5.6, the ISO shall reject the proposed regulated solution from further consideration during that planning cycle.

#### 31.2.5.5 Establishment of Trigger Date of Proposed Regulated Solutions

Upon receipt of all Developers' proposed regulated solutions pursuant to Section 31.2.5.1, the ISO will notify all Developers if any Developer has proposed a lead time for the implementation of its regulated solution that could result in a Trigger Date for the regulated solution within thirty-six months of the date of the ISO's presentation of the Viability and Sufficiency Assessment to the ESPWG, provided that the ISO will not disclose the identity of such Developer or the details of its project at that time. The ISO will independently analyze the lead time proposed by each Developer for the implementation of its regulated solution. The ISO

will use the Developer's estimate and the ISO's analysis to establish the ISO's Trigger Date for each regulated solution. The ISO will also establish benchmark lead times for proposed market-based solutions.

#### 31.2.5.6 Resolution of Deficiencies

Following initial review of the proposals, as described above, ISO staff will identify any reliability deficiencies in each of the proposed solutions. The Responsible Transmission Owner, Transmission Owner or Other Developer will discuss any identified deficiencies with the ISO staff. Other Developers and Transmission Owners that propose alternative regulated solutions shall have the option to remedy their proposals to address any deficiency within 30 days of notification by the ISO. With respect to regulated backstop solutions proposed by a Responsible Transmission Owner pursuant to Section 31.2.4.3, the Responsible Transmission Owner shall make necessary changes to its proposed backstop solution to address any reliability deficiencies identified by the ISO, and submit a revised proposal to the ISO for review within 30 days. The ISO shall review all such revised proposals to determine whether the identified deficiencies have been resolved.

#### 31.2.5.7 ISO Report of Evaluation Results

The ISO shall present its Viability and Sufficiency Assessment to stakeholders, interested parties, and the NYDPS for comment and will indicate at that time whether any of the proposed regulated solutions found to be viable and sufficient under this Section 31.2.5 will have a Trigger Date within thirty-six months of the date of the ISO's presentation of the Viability and Sufficiency Assessment to the ESPWG.

The ISO shall report in the CRP the results of its evaluation under this Section 31.2.5: (i) whether each proposed regulated backstop solution, alternative regulated solution, and market-

based solution is viable and is sufficient to satisfy the identified Reliability Need by the need date, and (ii) the Trigger Dates for the proposed regulated solutions.

### 31.2.6 ISO Evaluation and Selection of Proposed Regulated Transmission Solutions

#### 31.2.6.1 Submission of Project Information for Selection of Proposed Regulated Transmission Solution

If the ISO determines that the Trigger Date of any Developer's proposed regulated solution that was found to be viable and sufficient under Section 31.2.5 will occur within thirty-six months of the date of the ISO's presentation of the Viability and Sufficiency Assessment to the ESPWG, the ISO will request that all Developers of regulated transmission solutions that the ISO determined were viable and sufficient submit to the ISO their project information, as applicable, for: (i) a proposed regulated backstop transmission solution under Section 31.2.4.4.2, or (ii) a proposed alternative regulated transmission solution under Section 31.2.4.8.2. If the ISO determines that none of the Developers' proposed regulated solutions that were found to be viable and sufficient under Section 31.2.5 have a Trigger Date that will occur within the thirty-six month period, the ISO will not request further project information, perform the evaluation, or make a selection of a more efficient or cost effective regulated solution under this Section 31.2.6 for that planning cycle.

The ISO will make its request, if necessary, for project information under this Section 31.2.6.1 sufficiently in advance of the earliest Trigger Date of the viable and sufficient regulated solutions to enable the ISO to evaluate and select the more efficient or cost effective transmission solution. Upon the ISO's request for project information, the Developer shall submit such information for its regulated transmission solution within thirty (30) days or such other additional period as the ISO determines is reasonable. The Developer shall submit

additional project information required by the ISO within 15 days of the ISO's request. A Developer that fails to submit the required project information will not be eligible for its project to be considered in that planning cycle.

#### 31.2.6.2 Study Deposit for Proposed Regulated Transmission Solutions

A Developer that proposes a regulated backstop transmission solution or an alternative regulated transmission solution to satisfy the identified Reliability Need shall submit to the ISO, at the same time that it provides the project information required pursuant to Section 31.2.6.1, a study deposit of $100,000, which shall be applied to study costs and subject to refund as described in this Section 31.2.6.2.

The ISO shall charge, and a Developer proposing a regulated backstop transmission solution or an alternative regulated transmission solution shall pay, the actual costs of the ISO's evaluation of the Developer's proposed transmission solution for purposes of the ISO's selection of the more efficient or cost effective transmission solution to satisfy a Reliability Need for cost allocation purposes, including costs associated with the ISO's use of subcontractors. The ISO will track its staff and administrative costs, including any costs associated with using subcontractors, that it incurs in performing the evaluation of a Developer's proposed transmission solution under this Section 31.2.6 and any supplemental evaluation or re-evaluation of the proposed transmission solution. If the ISO or its subcontractors perform study work for multiple proposed transmission solutions on a combined basis, the ISO will allocate the costs of the combined study work equally among the applicable Developers. The ISO shall invoice the Developer monthly for study costs incurred by the ISO in evaluating the Developer's proposed transmission solution as described above. Such invoice shall include a description and an accounting of the study costs incurred by the ISO and estimated subcontractor costs. The

Developer shall pay the invoiced amount within thirty (30) calendar days of the ISO's issuance of the monthly invoice. The ISO shall continue to hold the full amount of the study deposit until settlement of the final monthly invoice; *provided, however,* if a Developer: (i) does not pay its monthly invoice within the timeframe described above, or (ii) does not pay a disputed amount into an independent escrow account as described below, the ISO may draw upon the study deposit to recover the owed amount. If the ISO must draw on the study deposit, the ISO shall provide notice to the Developer, and the Developer shall within thirty (30) calendar days of such notice make payments to the ISO to restore the full study deposit amount. If the Developer fails to make such payments, the ISO may halt its evaluation of the Developer's proposed transmission solution and may disqualify the Developer's proposed transmission solution from further consideration. After the conclusion of the ISO's evaluation of the Developer's proposed transmission solution or if the Developer: (i) withdraws its proposed transmission solution or (ii) fails to pay an invoiced amount and the ISO halts its evaluation of the proposed transmission solution, the ISO shall issue a final invoice and refund to the Developer any portion of the Developer's study deposit submitted to the ISO under this Section 31.2.6.2 that exceeds outstanding amounts that the ISO has incurred in evaluating that Developer's proposed transmission solution, including interest on the refunded amount calculated in accordance with Section 35.19a(a)(2) of FERC's regulations. The ISO shall refund the remaining portion within sixty (60) days of the ISO's receipt of all final invoices from its subcontractors and involved Transmission Owners.

In the event of a Developer's dispute over invoiced amounts, the Developer shall: (i) timely pay any undisputed amounts to the ISO, and (ii) pay into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Developer fails to

meet these two requirements, then the ISO shall not be obligated to perform or continue to perform its evaluation of the Developer's proposed transmission solution. Disputes arising under this section shall be addressed through the Dispute Resolution Procedures set forth in Section 2.16 of the ISO OATT and Section 11 of the ISO Services Tariff. Within thirty (30) Calendar Days after resolution of the dispute, the Developer will pay the ISO any amounts due with interest calculated in accordance with Section 35.19a(a)(2) of FERC's regulations.

#### 31.2.6.3 Evaluation of System Impact of Proposed Regulated Transmission Solution

A proposed regulated transmission solution that will have a significant adverse impact on the reliability of the New York State Transmission System shall not be eligible for selection by the ISO under Section 31.2.6.5. The ISO shall evaluate the system impacts for the entire Study Period of a proposed regulated transmission solution that the ISO has determined under Section 31.2.5 is viable and sufficient. The ISO shall perform power flow and short circuit studies for the proposed regulated transmission solutions and additional studies, as appropriate. If the ISO identifies a significant adverse impact based on these studies, the ISO shall request that the Developer make an adjustment to its proposed regulated transmission solution to address this impact and remain eligible for selection. The Developer shall submit the adjustment within 30 days of the ISO's notification.

If the Developer modifies its proposed regulated transmission solution, the ISO shall confirm that the adjusted solution still satisfies the viability and sufficiency requirements set forth in Section 31.2.5. If the ISO determines that the proposed regulated transmission solution does not satisfy the viability and sufficiency requirements or continues to have a significantly adverse impact on the reliability of the New York State Transmission System, the ISO shall remove the proposed solution from further consideration during that planning cycle.

#### 31.2.6.4 Evaluation of Regional Transmission Solutions to Address Local and Regional Reliability Needs More Efficiently or More Cost Effectively Than Local Transmission Solutions

The ISO will review the LTPs as they relate to BPTFs. The results of the ISO's analysis will be reported in the CRP.

##### 31.2.6.4.1 Evaluation of Regional Transmission Solutions to Address Local Reliability Needs Identified in Local Transmission Plans More Efficiently or More Cost Effectively than Local Transmission Solutions

The ISO, using engineering judgment, will determine whether proposed regional transmission solutions on the BPTFs may more efficiently or cost effectively satisfy reliability needs identified in the LTPs. If the ISO identifies that a regional transmission solution on the BPTFs has the potential to more efficiently or cost effectively satisfy the reliability need identified in the LTPs, it will perform a sensitivity analysis to determine whether the proposed regional transmission solution on the BPTFs would satisfy the reliability needs identified in the LTPs. If the ISO determines that the proposed regional transmission solutions on the BPTFs would satisfy the reliability need, the ISO will evaluate the proposed regional transmission solution using the metrics set forth in Section 31.2.6.5.1 to determine whether it may be a more efficient or cost effective solution on the BPTFs to satisfy the reliability needs identified in the LTPs than the local solutions proposed in the LTPs.

##### 31.2.6.4.2 Evaluation of Regional Transmission Solutions to Address Regional Reliability Needs More Efficiently or More Cost Effectively than Local Transmission Solutions

As referenced in Section 31.2.1.3, the ISO, using engineering judgment, will determine whether a regional transmission solution might more efficiently or more cost effectively satisfy an identified regional Reliability Need on the BPTFs that impacts more than one Transmission District than any local transmission solutions identified by the Transmission Owners in their

LTPs in the event the LTPs specify such transmission solutions are included to address local reliability needs.

#### 31.2.6.5 ISO Selection of More Efficient or Cost Effective Transmission Solution for Cost Allocation Purposes

A proposed regulated transmission solution – including a regulated backstop transmission solution submitted by a Responsible Transmission Owner pursuant to Section 31.2.4.3 and an alternative regulated transmission solution submitted by a Transmission Owner or Other Developer pursuant to Section 31.2.4.7 – that the ISO has determined satisfies the viability and sufficiency requirements in Section 31.2.5 and the system impact requirements in Section 31.2.6.3 shall be eligible under this Section 31.2.6.5 for selection in the CRP for the purpose of cost allocation and recovery under the ISO Tariffs. The ISO shall evaluate any eligible proposed regulated transmission solutions for the planning cycle using the metrics set forth in Section 31.2.6.5.1 below. For purposes of this evaluation, the ISO will review the information submitted by the Developer and determine whether it is reasonable and how such information should be used for purposes of the ISO evaluating each metric. The ISO may engage an independent consultant to review the reasonableness and comprehensiveness of the information submitted by the Developer and may rely on the independent consultant's analysis in evaluating each metric. The ISO shall select in the CRP for cost allocation purposes the more efficient or cost effective transmission solution to satisfy a Reliability Need in the manner set forth in Section 31.2.6.5.2 below.

##### 31.2.6.5.1 Metrics for Evaluating More Efficient or Cost Effective Regulated Transmission Solution to Satisfy Reliability Need

In determining which of the eligible proposed regulated transmission solutions is the more efficient or cost effective solution to satisfy the Reliability Need, the ISO will consider, and

will consult with the NYDPS regarding, the following metrics set forth in this Section 31.2.6.5.1 and rank each proposed solution based on the quality of its satisfaction of these metrics:

31.2.6.5.1.1 The capital cost estimates for the proposed regulated transmission solutions, including the accuracy of the proposed estimates. For this evaluation, the Developer shall provide the ISO with credible capital cost estimates for its proposed solution, with itemized supporting work sheets that identify all material and labor cost assumptions, and related drawings to the extent applicable and available. The work sheets should include an estimated quantification of cost variance, providing an assumed plus/minus range around the capital cost estimate.

The estimate shall include all components that are needed to meet the Reliability Need throughout the Study Period. To the extent information is available, the Developer should itemize: material and labor cost by equipment, engineering and design work, permitting, site acquisition, procurement and construction work, and commissioning needed for the proposed solution, all in accordance with Good Utility Practice. For each of these cost categories, the Developer should specify the nature and estimated cost of all major project components and estimate the cost of the work to be done at each substation and/or on each feeder to physically and electrically connect each facility to the existing system. The work sheets should itemize to the extent applicable and available all equipment for: (i) the proposed project; (ii) interconnection facilities (including Attachment Facilities and Direct Assignment Facilities); and (iii) System Upgrade Facilities, System Deliverability Upgrades, Network Upgrades, and Distribution Upgrades.

31.2.6.5.1.2 The cost per MW ratio of the proposed regulated transmission solutions. For this evaluation, the ISO will first determine the present worth, in dollars, of the total capital cost of the proposed solution in current year dollars. The ISO will then determine the MW value of the solution by summing the Reliability Need, in MW, with the additional improvement, in MW, that the proposed solution offers beyond serving the Reliability Need. The ISO will then determine the cost per MW ratio by dividing the present worth of the total capital cost by the MW value.

31.2.6.5.1.3 The expandability of the proposed regulated transmission solution. The ISO will consider the impact of the proposed solution on future construction. The ISO will also consider the extent to which any subsequent expansion will continue to use this proposed solution within the context of system expansion.

31.2.6.5.1.4 The operability of the proposed regulated transmission solution. The ISO will consider how the proposed solution may affect additional flexibility in operating the system, such as dispatch of generation, access to operating reserves, access to ancillary services, or ability to remove transmission for maintenance. The ISO will also consider how the proposed solution may affect the cost of operating the system, such as how it may affect the need for operating generation out of merit for reliability needs, reducing the need to cycle generation, or providing more balance in the system to respond to system conditions that are more severe than design conditions.

31.2.6.5.1.5 The performance of the proposed regulated transmission solution. The ISO will consider how the proposed project may affect the utilization of the system (*e.g.* interface flows, percent loading of facilities).

31.2.6.5.1.6 The extent to which the Developer of a proposed regulated transmission solution has the property rights, or ability to obtain the property rights, required to implement the solution. The ISO will consider whether the Developer: (i) already possesses the rights of way necessary to implement the solution; (ii) has completed a transmission routing study, which (a) identifies a specific routing plan with alternatives, (b) includes a schedule indicating the timing for obtaining siting and permitting, and (c) provides specific attention to sensitive areas (e.g., wetlands, river crossings, protected areas, and schools); or (iii) has specified a plan or approach for determining routing and acquiring property rights.

31.2.6.5.1.7 The potential issues associated with delay in constructing the proposed regulated transmission solution consistent with the major milestone schedule and the schedule for obtaining any permits and other certifications as required to timely meet the need.

#### 31.2.6.5.2 ISO Selection of More Efficient or Cost Effective Regulated Transmission Solution to Satisfy Reliability Need

The ISO shall select under this Section 31.2.6.5.2 the proposed regulated transmission solution, if any, that is the more efficient or cost effective transmission solution proposed in the planning cycle to satisfy the identified Reliability Need. The ISO shall report the selected regulated transmission solution in the CRP. The selected regulated transmission solution reported in the CRP shall be eligible to be triggered by the ISO to satisfy the identified Reliability Need pursuant to Section 31.2.8 at any point within thirty-six months of the date of the ISO's presentation of the Viability and Sufficiency Assessment to the ESPWG. An Other Developer or Transmission Owner of an alternative regulated transmission project shall not be eligible for cost allocation and cost recovery under the ISO OATT for its project unless its

project is selected pursuant to this Section 31.2.6.5.2. Once such project is selected, the Other Developer or Transmission Owner shall be eligible for cost allocation and cost recovery under the ISO OATT for its project. Within thirty (30) days of the ISO's selection of an alternative regulated transmission solution, the Other Developer or Transmission Owner shall submit to the ISO for the ISO's approval a proposed schedule and scope of work that describe the preparation work, if any, that the Developer must perform prior to the Trigger Date of the project, including a good faith estimate of the costs of such work. Costs will be recovered when the project is completed or halted in accordance with the cost recovery requirements set forth in Rate Schedule 10 of the ISO OATT, or as otherwise determined by the Commission. Actual project cost recovery, including any issues related to cost recovery and project cost overruns, will be submitted to and decided by the Commission.

### 31.2.7 Comprehensive Reliability Plan

Following the ISO's evaluation of the proposed market-based and regulated solutions to Reliability Need(s), the ISO will prepare a draft CRP that sets forth the ISO's findings regarding the viability and sufficiency of solutions, the trigger dates of regulated solutions, and any recommendations that implementation of regulated solutions (which may be a Gap Solution) is necessary to ensure system reliability. The draft CRP will reflect any input from the NYDPS. If the CRP cannot be completed in the two-year planning cycle, the ISO will notify stakeholders and provide an estimated completion date and an explanation of the reasons the additional time is required.

The ISO will include in the draft CRP the list of Developers that qualify pursuant to Section 31.2.4.1 and will identify the proposed solutions that it has determined under Section 31.2.5 are viable and sufficient to satisfy the identified Reliability Need(s) by the need date. The

ISO will identify in the CRP the regulated backstop solution that the ISO has determined will meet the Reliability Need by the need date and the Responsible Transmission Owner. If the ISO determines at the time of the issuance of the CRP that sufficient market-based solutions will not be available in time to meet a Reliability Need, and finds that it is necessary to take action to ensure reliability, it will state in the CRP that the development of regulated solutions (regulated backstop or alternative regulated solution) is necessary. The draft CRP will also include the results of the ISO's analysis of the LTPs consistent with Section 31.2.6.4.

The draft CRP shall indicate whether the ISO has determined that the Trigger Date to any proposed regulated solution will occur within thirty-six months of the date of ISO's presentation of the Viability and Sufficiency Assessment to the ESPWG. If the Trigger Date of any proposed regulated solution will occur within the thirty-six month period and the ISO makes a selection of the more efficient or cost effective transmission solution under Section 31.2.6.5.2, the draft CRP shall include the regulated transmission solution selected for cost allocation purposes pursuant to Section 31.2.6.5.2 as the more efficient or cost effective transmission solution to satisfy the Reliability Need(s) and shall indicate whether that transmission solution should be triggered. If: (i) none of the proposed regulated solutions has a Trigger Date within the thirty-six month period, or (ii) the Trigger Date of any proposed regulated solution will occur within the thirty-six month period but the ISO determines in its discretion that it is not necessary at that time to select a more efficient or cost effective transmission solution under Section 31.2.6.5.2 prior to the completion of the CRP, the draft CRP will not select a regulated transmission solution. If: (i) the Trigger Date of any proposed regulated solution will occur within the thirty-six month period, and (ii) the ISO selects a more efficient or cost effective solution subsequent to the completion of the CRP but prior to the completion of that thirty-six month period, the ISO shall issue an

updated CRP report pursuant to Section 31.2.7.3 that includes the regulated transmission solution selected for cost allocation purposes pursuant to Section 31.2.6.5.2 as the more efficient or cost effective transmission solution to satisfy the Reliability Need(s) and shall indicate whether that transmission solution should be triggered.

The draft CRP shall include a comparison of a proposed regional solution to an identified Reliability Need to an Interregional Transmission Project identified and evaluated under the "Analysis and Consideration of Interregional Transmission Projects" section of the Interregional Planning Protocol, if any. An Interregional Transmission Project proposed in the ISO's reliability planning process may be selected as a market based response, regulated backstop solution, or an alternative regulated solution under the provisions of the ISO's reliability planning process.

#### 31.2.7.1 Collaborative Governance Process

The ISO staff shall submit the draft CRP to the TPAS and ESPWG for review and comment. The ISO shall make available to any interested party sufficient information to replicate the results of the draft CRP. The information made available will be electronically masked and made available pursuant to a process that the ISO reasonably determines is necessary to prevent the disclosure of any Confidential Information or Critical Energy Infrastructure Information contained in the information made available. Following completion of the TPAS and ESPWG review, the draft CRP reflecting the revisions resulting from the TPAS and ESPWG review shall be forwarded to the Operating Committee for a discussion and action. The ISO shall notify the Business Issues Committee of the date of the Operating Committee meeting at which the draft CRP is to be presented. Following the Operating Committee vote, the draft CRP will be transmitted to the Management Committee for a discussion and action.

#### 31.2.7.2 Board Review, Consideration, and Approval of CRP

Following the Management Committee vote, the draft CRP, with working group, Operating Committee, and Management Committee input, will be forwarded to the ISO Board for review and action. Concurrently, the draft CRP will also be provided to the Market Monitoring Unit for its review and consideration of whether market rule changes are necessary to address an identified failure, if any, in one of the ISO's competitive markets. The Board may approve the draft CRP as submitted or propose modifications on its own motion, including the recommendations regarding the selection of transmission projects for cost allocation and cost recovery under the ISO Tariffs if such selection will occur during that planning cycle. If any changes are proposed by the Board, the revised CRP shall be returned to the Management Committee for comment. The Board shall not make a final determination on the draft CRP until it has reviewed the Management Committee comments. Upon final approval by the Board, the ISO shall issue the CRP to the marketplace by posting the CRP on its website. The ISO will provide the CRP to the appropriate regulatory agency(ies) for consideration and appropriate action.

The responsibilities of the Market Monitoring Unit that are addressed in the above section of Attachment Y to the ISO OATT are also addressed in Section 30.4.6.8.3 of the Market Monitoring Plan, Attachment O to the ISO Services Tariff.

#### 31.2.7.3 Updated CRP Report

If, pursuant to Section 31.2.7, the ISO identifies a proposed regulated transmission solution as the more efficient or cost effective transmission solution following the completion of the CRP, the ISO will prepare a draft updated CRP report that indicates the regulated transmission solution recommended for selection for cost allocation purposes pursuant to Section

31.2.6.5.2 as the more efficient or cost effective transmission solution to satisfy the Reliability Need(s) and shall indicate whether that transmission solution should be triggered at that time. The draft updated CRP report shall be reviewed in accordance with the stakeholder process set forth in Section 31.2.7.1 and will be then forwarded to the ISO Board for its review and action pursuant to Section 31.2.7.2.

#### 31.2.7.4 Reliability Disputes

Notwithstanding any provision to the contrary in this Attachment, the ISO OATT, or the ISO Services Tariff, in the event that a Market Participant or other interested party raises a dispute solely within the NYPSC's jurisdiction concerning ISO's final determination in the CRP that a proposed solution will or will not meet a Reliability Need, a Market Participant or other interested party seeking further review shall refer such dispute to the NYPSC for resolution, as provided for in the ISO Procedures. The NYPSC's final determination of such disputes shall be binding, subject only to judicial review in the courts of the State of New York pursuant to Article 78 of the New York Civil Practice Law and Rules.

#### 31.2.7.5 Posting of Approved Solutions

The ISO shall post on its website a list of all Developers that have undertaken a commitment to the ISO to build a project (which may be a regulated backstop solution, market-based response, alternative regulated response or gap solution) that is necessary to ensure system reliability, as identified in the CRP and approved by the appropriate governmental agency(ies) and/or authority(ies).

### 31.2.8 Determination of Necessity

#### 31.2.8.1 Determination of Necessity of a Regulated Solution

31.2.8.1.1 The ISO shall review proposals for market-based solutions pursuant to Sections 31.2.5, 31.2.8.3, and 31.2.13.1 of this Attachment Y. The ISO will not trigger a regulated solution if, based on this review, it determines prior to or at the Trigger Date for a regulated solution that sufficient market-based solutions are timely progressing to meet the Reliability Need by the need date. If the ISO decides not to trigger a regulated backstop solution or selected alternative regulated transmission solution, the Responsible Transmission Owner, Other Developer, or Transmission Owner will be eligible to recover its costs incurred up to that point in the same manner it may recover the costs of a halted project in accordance with Section 31.2.8.2.1 for the Responsible Transmission Owner and Section 31.2.8.2.2 for the Other Developer or Transmission Owner.

31.2.8.1.2 If: (i) the ISO determines that there are not sufficient market-based solutions to meet the identified Reliability Need by the need date, (ii) the regulated backstop solution proposed by the Responsible Transmission Owner is the only proposed viable and sufficient regulated solution or is selected by the ISO as the more efficient or cost effective transmission solution to meet the identified Reliability Need, and (iii) the Trigger Date for the regulated backstop solution has or will occur within thirty-six months of the date of the ISO's presentation of the Viability and Sufficiency Assessment to the ESPWG, the ISO will trigger the regulated backstop solution at its Trigger Date. The ISO will inform the Responsible Transmission Owner that it should submit the regulated

backstop solution to the appropriate governmental agency(ies) and/or authority(ies) to begin the necessary approval process to site, construct, and operate the solution. In response to the ISO's request, the Responsible Transmission Owner shall make such a submission to the appropriate governmental agency(ies) and/or authority(ies).

31.2.8.1.3 If: (i) the ISO determines that there are not sufficient market-based solutions to meet the identified Reliability Need by the need date; (ii) the ISO selects an alternative regulated transmission solution as the more efficient or cost-effective transmission solution to meet the identified Reliability Need; (iii) the Trigger Date for the regulated backstop solution is later than the Trigger Date for the selected alternative regulated transmission solution; and (iv) the Trigger Date for the selected alternative regulated transmission solution has or will occur within thirty-six months of the date of the ISO's presentation of the Viability and Sufficiency Assessment to the ESPWG, the ISO shall trigger the selected alternative regulated transmission solution at its Trigger Date. The ISO will inform the Other Developer or Transmission Owner that it should submit the selected alternative regulated transmission solution to the appropriate governmental agency(ies) and/or authority(ies) to begin the necessary approval process to site, construct, and operate the solution. In response to the ISO's request, the Other Developer or Transmission Owner shall make such a submission to the appropriate governmental agency(ies) and/or authority(ies). Prior to the Trigger Date for the regulated backstop solution, the ISO will review the status of the development by the Other Developer or Transmission Owner of

the selected alternative regulated transmission solution, including, but not limited to, reviewing: (i) whether the Developer has executed a Development Agreement or requested that it be filed unexecuted with the Commission pursuant to Section 31.2.8.1.6; (ii) whether the Developer is timely progressing against the milestones set forth in the Development Agreement; and (iii) the status of the Developer's obtaining required permits or authorizations, including whether the Developer has received its Article VII certification or other applicable siting permits or authorizations under New York State law. If, based on its review, the ISO determines prior to or at the Trigger Date for the regulated backstop solution that it is necessary for the Responsible Transmission Owner to proceed with a regulated backstop solution in parallel with the selected alternative regulated transmission solution to ensure the identified Reliability Need is satisfied by the need date, the ISO will trigger the regulated backstop solution and report to stakeholders the reasons for its determination. The Responsible Transmission Owner shall proceed with due diligence to develop its regulated backstop solution in accordance with Good Utility Practice and to submit its proposed solution to the appropriate governmental agency(ies) and/or authority(ies), unless or until notified by the ISO that it has determined that the regulated backstop solution is no longer needed as described in Section 31.2.8.2.1 below. If, based on its review, the ISO decides not to trigger the regulated backstop solution, the ISO will notify the Responsible Transmission Owner that its regulated backstop solution is no longer needed and will not be triggered. In such case, the Responsible Transmission Owner shall be eligible to recover its costs incurred up

to that point in the same manner as it may recover the costs of a halted project in accordance with Section 31.2.8.2.1.

31.2.8.1.4 If: (i) the ISO determines that there are not sufficient market-based solutions to meet the identified Reliability Need by the need date; (ii) the ISO selects an alternative regulated transmission solution as the more efficient or cost-effective transmission solution to meet the identified Reliability Need; (iii) the Trigger Date for the regulated backstop solution is earlier than the Trigger Date for the selected alternative regulated transmission solution; and (iv) the Trigger Date for the regulated backstop solution has or will occur within thirty-six months of the date of the ISO's presentation of the Viability and Sufficiency Assessment to the ESPWG, the ISO shall trigger both the selected alternative regulated transmission solution and the regulated backstop solution at the Trigger Date for the regulated backstop solution. The ISO will inform the Responsible Transmission Owner that proposed the regulated backstop solution and the Other Developer or Transmission Owner that proposed the selected alternative regulated transmission solution that they should submit the proposed solutions to the appropriate governmental agency(ies) and/or authority(ies) to begin the necessary approval process to site, construct, and operate the solution. In response to the ISO's request, the Responsible Transmission Owner, Other Developer or Transmission Owner shall make such a submission to the appropriate governmental agency(ies) and/or authority(ies).

31.2.8.1.5 The ISO may make its determination regarding the triggering of a regulated solution pursuant to Sections 31.2.8.1.1 through 31.2.8.1.4 in the CRP or at any time before the approval of the next CRP.

31.2.8.1.6 If the selected regulated transmission solution is an alternative regulated transmission solution, the ISO shall tender the Other Developer or Transmission Owner that proposed the selected alternative regulated transmission solution – as soon as reasonably practicable considering the project's Trigger Date following the ISO's selection of the proposed solution – a draft Development Agreement with draft appendices completed by the ISO to the extent practicable for review and completion by the Developer. The draft Development Agreement shall be in the form of the ISO's Commission-approved Development Agreement, which is in Appendix C in Section 31.7 of this Attachment Y. The ISO and the Developer shall finalize the Development Agreement and appendices and negotiate concerning any disputed provisions. For purposes of finalizing the Development Agreement, the ISO shall provide the Developer with the date by which the selected project must be in-service to satisfy the Reliability Need, and the ISO and Developer shall develop the description and dates for the milestones necessary to develop and construct the selected project by the required in-service date, including the milestones for obtaining all necessary authorizations. Unless otherwise agreed by the ISO and the Developer, the Developer must execute the Development Agreement within three (3) months of the ISO's tendering of the draft Development Agreement; *provided, however*, if, during the negotiation period, the Developer determines that negotiations are at an impasse, it may

request in writing that the ISO file the Development Agreement in unexecuted form with the Commission. If the Development Agreement resulting from the negotiation between the ISO and the Developer does not conform with the Commission-approved standard form in Appendix C in Section 31.7 of this Attachment Y, the ISO shall file the agreement with the Commission for its acceptance within thirty (30) Business Days after the execution of the Development Agreement by both parties. If the Developer requests that the Development Agreement be filed unexecuted, the ISO shall file the agreement at the Commission within thirty (30) Business Days of receipt of the request from the Developer. The ISO will draft to the extent practicable the portions of the Development Agreement and appendices that are in dispute and will provide an explanation to the Commission of any matters as to which the parties disagree. The Developer will provide in a separate filing any comments that it has on the unexecuted agreement, including any alternative positions it may have with respect to the disputed provisions.

31.2.8.1.7 Upon the ISO's and Developer's execution of the Development Agreement or the ISO's filing of an unexecuted Development Agreement with the Commission pursuant to Section 31.2.8.1.6, the ISO and Developer shall perform their respective obligations in accordance with the terms of the Development Agreement that are not in dispute, subject to modifications by the Commission. The Connecting Transmission Owner(s) and Affected Transmission Owner(s) that are identified in Attachment X of the ISO OATT in connection with the selected alternative regulated transmission solution shall act in good faith in timely

performing their obligations that are required for the Developer to satisfy its obligations under the Development Agreement.

31.2.8.1.8 Other Developers and Transmission Owners proposing alternative regulated solutions that the ISO has determined will resolve the identified Reliability Need may submit these proposals to the appropriate governmental agency(ies) and/or authority(ies) for review. The ISO does not determine the solution that will be permitted by the appropriate governmental agency(ies) and/or authority(ies) with jurisdiction over siting or whether the regulated backstop solution or an alternative regulated solution will be constructed to address the identified Reliability Need. If the appropriate governmental agency(ies) and/or authority(ies) makes a final determination that an alternative regulated solution should be permitted and constructed to satisfy a Reliability Need and that the regulated backstop solution should not proceed, implementation of the alternative regulated solution will be the responsibility of the Transmission Owner or Other Developer that proposed the alternative regulated solution, and the Responsible Transmission Owner will not be responsible for addressing the Reliability Need through the implementation of its regulated backstop solution. Should a regulated solution not be implemented, the ISO may request a Gap Solution pursuant to Section 31.2.11 of this Attachment Y.

**31.2.8.2 Halting and Related Cost Recovery Requirements**

31.2.8.2.1 If the ISO has triggered a regulated backstop solution under Sections 31.2.8.1.2, 31.2.8.1.3, 31.2.8.1.4, or 31.2.8.1.5, the ISO will immediately notify the Responsible Transmission Owner, post such notice on its website, and will

state in the next CRP if it determines that the regulated backstop solution is no longer needed and should be halted because either: (i) the ISO has determined that there are sufficient market-based solutions to ensure that the identified Reliability Need is met by the need date, or (ii) the ISO: (A) has triggered an alternative regulated transmission solution that the ISO selected in the CRP as the more efficient or cost effective transmission solution and (B) has determined that it is no longer necessary for the Responsible Transmission Owner to proceed with a regulated backstop solution in parallel with the selected alternative regulated transmission solution to ensure the identified Reliability Need is satisfied by the need date. In making its determination under Section 31.2.8.2.1(ii), the ISO will review the status of the development by the Other Developer or Transmission Owner of the selected alternative regulated transmission solution, including, but not limited to, reviewing: (i) whether the Developer has executed a Development Agreement or requested that it be filed unexecuted with the Commission pursuant to Section 31.2.8.1.6; (ii) whether the Developer is timely progressing against the milestones set forth in the Development Agreement; and (iii) the status of the Developer's obtaining required permits or authorizations, including whether the Developer has received its Article VII certification or other applicable siting permits or authorizations under New York State law.

If a regulated backstop solution is halted by the ISO, all of the costs incurred and commitments made by the Responsible Transmission Owner up to that point, including reasonable and necessary expenses incurred to implement an orderly termination of the project, will be recoverable by the Responsible

Transmission Owner under the cost recovery mechanism in Rate Schedule 10 of this tariff regardless of the nature of the solution.

31.2.8.2.2 If the ISO has triggered an alternative regulated transmission project under Sections 31.2.8.1.3 or 31.2.8.1.4 that the ISO has selected as the more efficient or cost effective solution, the ISO will immediately notify the Other Developer or Transmission Owner, post such notice on its website, and will state in the next CRP if it determines that the regulated transmission solution is no longer needed and should be halted because the ISO has determined that there are sufficient market-based solutions to ensure that the identified Reliability Need is met by the need date.

If a selected alternative regulated transmission solution is halted by the ISO, all of the costs incurred and commitments made by the Other Developer or Transmission Owner up to that point, including reasonable and necessary expenses incurred to implement an orderly termination of the project, will be recoverable by the Other Developer or Transmission Owner under the cost recovery mechanism in Rate Schedule 10 of this tariff.

31.2.8.2.3 Once the Responsible Transmission Owner receives state regulatory approval of the regulated backstop solution, or, if state regulatory approval is not required, once the Responsible Transmission Owner receives necessary regulatory approval, the entry of a market-based solution or an alternative regulated transmission solution will not result in the halting by the ISO of the regulated backstop solution pursuant to Section 31.2.8.2.1. Similarly, once the Other Developer or Transmission Owner receives its state regulatory approval or any

other necessary regulatory approval of its triggered alternative regulated transmission solution, the entry of a market-based solution will not result in the halting by the ISO of the regulated transmission solution pursuant to Section 31.2.8.2.2.

31.2.8.2.4 The ISO is not required to review market-based solutions to determine whether they will meet the identified Reliability Need by the need date after the triggered alternative regulated transmission solution or regulated backstop solution has received federal and state regulatory approval, unless a federal or state regulatory agency requests the ISO to conduct such a review. The ISO will report the results of its review to the federal or state regulatory agency, with copies to the Responsible Transmission Owner, Other Developer, or Transmission Owner.

31.2.8.2.5 If the appropriate federal, state or local agency(ies) does not approve a necessary authorization for the triggered regulated backstop solution or alternative regulated transmission solution, all of the necessary and reasonable costs incurred and commitments made up to the final federal, state or local regulatory decision, including reasonable and necessary expenses incurred to implement an orderly termination of the project, will be recoverable by the Responsible Transmission Owner, Other Developer, or Transmission Owner under the ISO cost recovery mechanism in Rate Schedule 10 of the ISO OATT regardless of the nature of the solution.

31.2.8.2.6 If a necessary federal, state or local authorization for a triggered alternative regulated transmission solution or regulated backstop solution is

withdrawn, all expenditures and commitments made up to that point including reasonable and necessary expenses incurred to implement an orderly termination of the project, will be recoverable under the ISO cost recovery mechanism in Rate Schedule 10 of the ISO OATT by the Responsible Transmission Owner, Other Developer, or Transmission Owner regardless of the nature of the solution.

31.2.8.2.7 If a material modification to the regulated backstop solution or the alternative regulated transmission solution is proposed by any federal, state or local agency, the Responsible Transmission Owner, Other Developer, or Transmission Owner will request the ISO to conduct a supplemental reliability review. If the ISO identifies any reliability deficiency in the modified solution, the ISO will so advise the Responsible Transmission Owner, Other Developer, or Transmission Owner and the appropriate federal, state or local regulatory agency(ies).

**31.2.8.3 Criteria for Cutoff Date of Market-Based Solution**

31.2.8.3.1 The ISO will apply the criteria in this Section 31.2.8.3 for determining the cutoff date for a determination that a market-based solution will not be available to meet a Reliability Need by the need date.

31.2.8.3.2 In the first instance, the ISO shall employ its procedures for monitoring the viability of a market-based solution to determine when it may no longer be viable. Under the conditions where a market-based solution is proceeding after the Trigger Date for the relevant regulated solution, it becomes even more critical for the ISO to conduct a continued analysis of the viability of such market-based solutions.

31.2.8.3.3 The Developer of such a market-based solution shall submit updated information to the ISO twice during each reliability planning process cycle, first during the input phase of the RNA, and again during the solutions phase during the period allowed for the solicitation for market-based and regulated solutions. If no solutions are requested in a particular year, then the second update will be provided during the ISO's analysis of whether existing solutions continue to meet identified Reliability Needs. The updated information of the project status shall include: status of final permits, status of major equipment, current status of construction schedule, estimated in-service date, any potential impediments to completion by the Target Year, and any other information requested by the ISO.

31.2.8.3.4 The Developer shall immediately report to the ISO when it has any indication of a material change in the project status or that the project in-service date may slip beyond the Target Year. A material change shall include, but not be limited to, a change in the financial viability of the Developer, a change in siting status, or a change in a major element of the project development.

31.2.8.3.5 Based upon the above information, the ISO will perform an independent review of the development status of the market-based solution to determine whether it remains viable to meet the identified Reliability Need by the need date. If the ISO, at any time, learns of a material change in the project status of a market-based solution, it may, at that time, make a determination as to the continued viability of such project.

31.2.8.3.6 The ISO, prior to making a determination about the viability of a specific proposed solution, will communicate its intended determination to the project

Developer along with the basis for its intended determination. The ISO shall provide the Developer a reasonable period (not more than 2 weeks) to respond to the ISO's intended determination, including an opportunity to provide additional information to the ISO to support the continued viability of the proposed solution.

31.2.8.3.7 If the ISO determines that a market-based solution that is needed to meet an identified Reliability Need is no longer viable, it will request that a regulated solution proceed or seek other measures including, but not limited to, a Gap Solution, to ensure the reliability of the system.

31.2.8.3.8 If the ISO determines that the market-based solution is still viable, but that its in-service date is likely to slip beyond the Target Year, the ISO may, if needed, request the Responsible Transmission Owner to prepare a Gap Solution in accordance with the provisions of Section 31.2.11 of this Attachment Y.

### 31.2.9 Process for Consideration of Regulated Backstop Solution and Alternative Regulated Solutions

Upon a determination by the ISO under Section 31.2.8 that a regulated solution should proceed, the Responsible Transmission Owner, Other Developer, or Transmission Owner will make a presentation to the ESPWG that will provide a description of the regulated solution. The presentation will include a non-binding preliminary cost estimate of that regulated solution; provided, however, that the Responsible Transmission Owner, Other Developer or Transmission Owner shall be entitled to full recovery of all reasonably incurred costs as described in Rate Schedule 10 of the ISO OATT. The ISO and stakeholders through this process will have the opportunity to review and discuss the scope of the projects and their associated non-binding preliminary cost estimates prior to implementation.

### 31.2.10 Process for Addressing Inability of Responsible Transmission Owner, Other Developer, or Transmission Owner to Complete Triggered Regulated Solution

31.2.10.1 If: (i) the regulated transmission solution selected and triggered by the ISO is an alternative regulated transmission solution, and (ii) one of the following events occur: (A) the Other Developer or Transmission Owner that proposed the alternative regulated transmission solution does not execute the Development Agreement, or does not request that it be filed unexecuted with the Commission, within the timeframes set forth in Section 31.2.8.1.6, or (B) an effective Development Agreement is terminated under the terms of the agreement prior to the completion of the term of the agreement, the ISO may take the following actions as soon as practicable after the occurrence of the event:

31.2.10.1.1 If the Development Agreement has been filed with and accepted by the Commission, the ISO shall, upon terminating the Development Agreement under the terms of the agreement, file a notice of termination with the Commission.

31.2.10.1.2 The ISO may revoke its selection of the alternative regulated transmission solution and the eligibility of the Other Developer or Transmission Owner to recover its costs for the project; *provided, however*, the Other Developer or Transmission Owner may recover its costs to the extent provided in Sections 31.2.8.2.2, 31.2.8.2.5, and 31.2.8.2.6 or as otherwise determined by the Commission.

31.2.10.1.3 If the ISO determines that it must identify a solution prior to the approval of the CRP for the next planning cycle to satisfy the Reliability Need by the need date, the ISO may: (i) direct the Responsible Transmission Owner to proceed with its regulated backstop solution if it has not yet been halted by the ISO pursuant to

Section 31.2.8.2.1, (ii) request that the Responsible Transmission Owner complete the selected alternative regulated transmission solution, and/or (iii) proceed with the Gap Solution process under Section 31.2.11.

31.2.10.1.4 If the Responsible Transmission Owner agrees to complete the selected alternative regulated transmission solution, the Responsible Transmission Owner and the Other Developer or Transmission Owner that proposed the selected alternative regulated transmission solution shall work cooperatively with each other to implement the transition, including negotiating in good faith with each other to transfer the project; *provided, however*, that the transfer is subject to: (i) any required approvals by the appropriate governmental agency(ies) and/or authority(ies), (ii) any requirements or restrictions on the transfer of Developer's rights-of-way under law, conveyance, or contract, and (iii), if the Developer is a New York public authority, any requirements or restrictions on the transfer under the New York Public Authorities Law; *provided, further*, that the Responsible Transmission Owner and the Developer will address any disputes regarding the transfer of the project in accordance with the dispute resolution provisions in Article 11 of the ISO Services Tariff.

31.2.10.2 If: (i) the regulated transmission solution selected and triggered by the ISO is the Responsible Transmission Owner's regulated backstop solution or the regulated backstop solution has been triggered by the ISO under Sections 31.2.8.1.2, 31.2.8.1.3, or 31.2.8.1.4, and the regulated backstop solution has not been halted by the ISO under Section 31.2.8.2.1, and (ii) the ISO determines that the Responsible Transmission Owner: (A) has not submitted its proposed

regulated backstop solution for necessary regulatory action within a reasonable period of time, (B) is unable to or fails to obtain the approvals or property rights necessary to construct the project, or (C) is otherwise not taking the actions necessary to construct the project to satisfy the Reliability Need by the need date, the ISO shall: (i) submit a report to the Commission for its consideration and determination of whether action is appropriate under federal law, and (ii) take such action as it reasonably considers is appropriate to ensure that the Reliability Need is satisfied by the need date.

### 31.2.11 Gap Solutions

31.2.11.1 The ISO will commence the Gap Solution process under this Section 31.2.11 if: (i) the ISO determines within the biennial reliability planning process that neither market-based solutions nor regulated solutions can satisfy one or more identified Reliability Need(s) by the need date and sets forth its determination in the CRP that a Gap Solution is necessary; (ii) the ISO Board, after consultation with the NYDPS, determines that there is an imminent threat to the reliability of the New York State Transmission System that cannot be timely addressed within the biennial reliability planning process; or (iii) a Generator Deactivation Assessment performed by the ISO in accordance with Section 31.2.11.2.4 identifies a Reliability Need arising on the New York State Transmission System that cannot be timely addressed within the biennial reliability planning process. Reliability Needs that the ISO determines can be addressed within the biennial reliability planning process shall be addressed in the

current or next planning cycle and will not be addressed through the Gap Solution process set forth in this Section 31.2.11.

**31.2.11.2 Generator Deactivation Requirements**

31.2.11.2.1 A Market Participant must provide the ISO with a minimum of 365 days prior notice (such period beginning after its Generator Deactivation Notice has been determined to be complete) before its Generator may be Retired or enter into a Mothball Outage, except for Generators reclassified as Retired pursuant to Sections 5.18.2.3.1 or 5.18.3.3.1 of the ISO Services Tariff or as provided for an RMR Generator under an RMR Agreement. The Market Participant shall provide this notice to the ISO by submitting a Generator Deactivation Notice in the form set forth in Appendix E to this Attachment Y, along with all information required by that form, the supporting certification from a duly authorized officer, and the information required for an Initiating Generator in accordance with Sections 31.9.2, and 31.9.5 through 31.9.7 of Appendix F of this Attachment Y. The Market Participant must indicate in the Generator Deactivation Notice whether it proposes for its Generator to be Retired or to enter into a Mothball Outage greater than 365 days after the Generator Deactivation Assessment Start Date. If so, the Market Participant must specify in the Generator Deactivation Notice its proposed date for its Generator to be Retired or to enter into a Mothball Outage. The Market Participant may also indicate in the Generator Deactivation Notice whether it has an interest in deactivating its Generator earlier than 365 days after the Generator Deactivation Assessment Start Date if the ISO determines that a Reliability Need is not created by the deactivation of the Generator.

31.2.11.2.2 The 365-day notice period applicable to a Generator proposing to be Retired or enter into a Mothball Outage will begin to run once the ISO has issued a written notice to the Market Participant indicating that the Generator Deactivation Notice, including the supporting information and certification, is complete. For purposes of this Section 31.2.11, "complete" shall mean sufficiently complete for the ISO to begin its review of the reliability impacts that would result from a Generator being Retired or entering into a Mothball Outage under this Attachment Y and to review as required by Sections 31.2.11.7 and 31.2.11.8 the information provided in accordance with Appendix F of this Attachment Y. Within ten (10) business days of receiving a Generator Deactivation Notice, the ISO shall review the notice form, along with the supporting information and affidavit submitted with it, and will inform the Market Participant whether its submission is complete or whether additional information is required. The Market Participant shall provide the ISO with any requested additional information, and the ISO will promptly review the information to determine whether the Market Participant's notice is complete. Within ten (10) business days of the ISO receiving all additional information it requested, the ISO will inform the Market Participant whether its submission is complete, or whether further information is needed. Upon its determination that a submitted Generator Deactivation Notice is complete, the ISO will concurrently notify the Generator and post a notice on its website that the Generator Deactivation Notice has been determined to be complete. The Market Participant has a continuing obligation to promptly submit any additional information requested by the ISO in connection

with the ISO's evaluation under this Attachment Y, as required by Section 31.9.4 of Appendix F of Attachment Y, and assessment of market impacts under Section 23 of Attachment H of the ISO Services Tariff.

31.2.11.2.3 Within 20 days of a Market Participant's Generator entering into an ICAP Ineligible Forced Outage, the Market Participant shall submit the information required for an Initiating Generator in accordance with Sections 31.9.2 and 31.9.5 through 31.9.7 of Appendix F of this Attachment Y. The Market Participant has a continuing obligation to promptly submit any additional information requested by the ISO in connection with the ISO's evaluation under this Attachment Y, required by Section 31.9.4 of Appendix F of this Attachment Y, and assessment of market impacts under Section 23 of Attachment H of the ISO Services Tariff.

31.2.11.2.4 Following the Generator Deactivation Assessment Start Date, the ISO will perform, in coordination with the Responsible Transmission Owner(s) identified by the ISO, a Generator Deactivation Assessment concerning the Generator identified in the Generator Deactivation Notice or a Generator that has entered into an ICAP Ineligible Forced Outage in accordance with Section 5.18.2.1 of the ISO Services Tariff. The ISO will conduct the necessary reliability studies to review the impact on the reliability of the BPTFs that would result from the Generator being Retired, entering into a Mothball Outage, or being unavailable due to an ICAP Ineligible Forced Outage. The Responsible Transmission Owner(s) will conduct the necessary reliability studies to review the impact on the reliability of the non-BPTFs that are part of the New York State Transmission System, which studies the ISO will review and verify. For the Generator

Deactivation Assessment, the ISO will use the most recent base case from the reliability planning process and updates in accordance with ISO Procedures. As part of the assessment, the ISO shall review whether any potential Reliability Need resulting from the Generator being Retired, entering into a Mothball Outage, or being unavailable due to an ICAP Ineligible Forced Outage can be addressed through the adoption of alternative ISO or Transmission Owner operating procedures or by updates to Local Transmission Owner Plans, other than an agreement with the Generator addressed in the Generator Deactivation Notice or a Generator already in a Mothball Outage, an ICAP Ineligible Forced Outage, or that has been mothballed since before May 1, 2015. Within ninety (90) days of the Generator Deactivation Assessment Start Date, the ISO shall concurrently notify the Generator and post on its website the results of the Generator Deactivation Assessment, including whether a Reliability Need would arise from the Generator being Retired, entering into a Mothball Outage, or being unavailable due to an ICAP Ineligible Forced Outage.

31.2.11.2.5 If: (i) the ISO determines in the Generator Deactivation Assessment that a Reliability Need would not arise from a Market Participant's Generator being Retired or entering into a Mothball Outage, and (ii) the Market Participant indicated in the Generator Deactivation Notice an interest in deactivating its Generator earlier than the completion of the 365-day notice period, the ISO will notify the Market Participant when its Generator may be Retired or enter into a Mothball Outage, as designated in the Generator Deactivation Notice, which

deactivation date shall be no earlier than 120 days after the Generator Deactivation Assessment Start Date.

**31.2.11.3 Solicitation of Gap Solutions**

Upon the determination of a Reliability Need pursuant to Section 31.2.11.1 above, the ISO shall solicit proposed Gap Solutions and market-based solutions to address the identified Reliability Need. In response to the ISO's request, the Responsible Transmission Owner must submit: (i) a proposed Gap Solution, which solution must satisfy the project information requirements in Section 31.2.4.4.1 and should to the extent practicable satisfy completely the identified Reliability Need, and (ii) a conceptual permanent solution to the identified Reliability Need. Any Developer may also propose a Gap Solution to the identified Reliability Need, which solution must satisfy the project information requirements: (i) in Section 31.2.4.6 for a market-based solution, or (ii) in Section 31.2.4.8.1 for alternative regulated solutions. A Gap Solution may include generation, transmission, or demand response solutions. Only Developers that have been determined by the ISO to be qualified under Section 31.2.4.1.1.2 may propose a transmission Gap Solution. As part of the Developer's submission of its proposed Gap Solution, the Developer shall provide the information required for a proposed Gap Solution in accordance with Sections 31.9.3, and 31.9.5 through 31.9.7 of Appendix F of this Attachment Y. It shall also provide the information required by Section 31.9.4 of Appendix F of this Attachment Y. A Developer shall submit its proposed Gap Solution within the timeframe specified by the ISO; *provided, however*, that if the Reliability Need is identified under Section 31.2.11.1(iii) as a result of a Generator Deactivation Assessment, the Developer must submit its proposed Gap Solution within thirty (30) days of the ISO's request.

#### 31.2.11.4 Review and Notification of Generator(s) Currently in an Outage State

If the ISO determines that a Market Participant's Generator, other than an Initiating Generator, that is in a Mothball Outage, an ICAP Ineligible Forced Outage, or has been mothballed since before May 1, 2015, may be capable of satisfying in whole or in part the Reliability Need, the ISO will notify the Market Participant that its Generator is subject to review to determine whether it can satisfy the Reliability Need as a possible Gap Solution. The Market Participant shall provide the ISO within twenty (20) days of the ISO's issuance of the notification the information required for a Generator identified under this Section 31.2.11.4 in accordance with Sections 31.9.3.1, 31.9.3.2, and 31.9.5 through 31.9.7 of Appendix F of this Attachment Y (a) if it has not previously provided such information, or (b) if it has previously provided such information, it shall update all such information, not limited to the updates required by Section 31.9.4 of Appendix F of this Attachment Y. When the return to service of a Generator in a Mothball Outage or an ICAP Ineligible Forced Outage is the Gap Solution, the return to service procedures set forth in Section 5.18.4 of the Services Tariff shall apply.

#### 31.2.11.5 ISO Submission of Information to the NYPSC

Upon the NYDPS's request, the ISO will submit to the NYPSC the information requested that the ISO receives from Developers for their proposed Gap Solution(s), and information it receives pursuant to Sections 31.2.11.2.1 through 31.2.11.2.4, 31.2.11.3, and 31.2.11.4 from Initiating Generators, and generators that are in a Mothball Outage, an ICAP Ineligible Forced Outage, or have been mothballed since before May 1, 2015. For each such submission, the ISO will request in accordance with the NYPSC's rules and regulations that any information that the ISO must maintain as confidential pursuant to Section 31.2.12.6 or pursuant to Attachment F of the OATT, be treated as confidential and non-public by the NYPSC.

**31.2.11.6 Evaluation of Gap Solutions**

The ISO shall evaluate all proposed Gap Solution proposals, all Generators identified pursuant to Section 31.2.11.4, and the conceptual permanent solution provided by the Responsible Transmission Owner pursuant to Section 31.2.11.3 to determine whether each is viable and sufficient to satisfy individually or in conjunction with other solutions the identified Reliability Need. If the Reliability Need is identified under Section 31.2.11.1(iii) as a result of a Generator Deactivation Assessment, the ISO will perform this evaluation within one hundred twenty (120) days of the due date for receiving proposed Gap Solutions established in Section 31.2.11.3. The ISO shall perform this viability and sufficiency evaluation consistent with the requirements set forth in Sections 31.2.5.3 and 31.2.5.4 of this Attachment Y. The ISO shall coordinate with the Responsible Transmission Owner(s), as necessary, in performing its evaluation. If the ISO determines that there are adequate viable and sufficient market-based solutions to satisfy completely the identified Reliability Need, the ISO will conclude the Gap Solution process under this Section 31.2.11, and the ISO will monitor the development of the market-based solutions in accordance with ISO Procedures. The ISO shall present the results of its viability and sufficiency assessment to interested parties, including its findings regarding whether the Gap Solution process has been concluded because there are adequate market-based solutions to satisfy completely the identified Reliability Need. If the ISO identifies any non-generation Viable and Sufficient Gap Solution(s) that would satisfy in whole or in part an identified Reliability Need, the ISO shall provide to the NYPSC: (i) a list of the proposed Viable and Sufficient Gap Solution(s), and (ii) the results of the ISO's viability and sufficiency assessment performed in accordance with Section 31.2.11.6.

### 31.2.11.7 ISO Review of Information Pursuant to Appendix F

The ISO shall review, verify and/or validate to the extent necessary the information provided in accordance with Sections 31.2.11.2, 31.2.11.3, and 31.2.11.4 and Appendix F of this Attachment Y. The ISO's review, verification and/or validation, as applicable, of the financing cost of each capital expense that the ISO determines is necessary in accordance with Good Utility Practice shall consider the market interest rate available to the Market Party.

31.2.11.7.1 The ISO may reject, and may require a Market Party to re-submit, or substantiate information (including estimates) that the ISO determines is not adequately supported or otherwise verifiable. The Market Party shall promptly provide any additional information that the ISO may request, and update and revise information previously provided, and provide new information as set forth in Section 31.9.4 of Appendix F of this Attachment Y. Upon the ISO's prior notice, the Market Party shall make qualified representatives available to answer the ISO's question(s) and otherwise facilitate the ISO's review of the information.

### 31.2.11.8 Reliability Net Cost Determinations

31.2.11.8.1 Determinations pursuant to this section are solely for purposes of determining (a) the RMR Offer Price in accordance with Section 23.4.5.8.2 of the ISO Services Tariff, and (b) the RMR Avoidable Cost of Initiating Generators and Generators that are determined to be a Viable and Sufficient Gap Solution for a Reliability Need. The ISO shall determine the cost (net of estimated revenues, as applicable) of each Initiating Generator and Viable and Sufficient Gap Solution for a Reliability Need. This determination for a Generator shall be its "RMR Avoidable Costs." The ISO shall use the costs, revenues, and other information

submitted in accordance with Sections 31.2.11.2, 31.2.11.3 and 31.2.11.4, or Appendix F, or Sections 31.2.11.7 and 31.2.11.8 of this Attachment Y that it verifies and/or validates, as applicable. If the ISO cannot verify and/or validate, as applicable, a cost or revenue submitted by a Market Party, the ISO shall substitute an estimated value. The ISO's cost determinations pursuant to this Section shall be for the shorter of (i) the duration of the Reliability Need identified by the ISO in its request for Gap Solutions, and (ii) the period identified by the ISO that an Initiating Generator or Viable and Sufficient Gap Solution can satisfy the Reliability Need.

31.2.11.8.1.1 Cost savings due to an Initiating Generator's continuation of service. Costs submitted in accordance with Sections 31.2.11.2, 31.2.11.3 and 31.2.11.4, or Appendix F, or Sections 31.2.11.7 and 31.2.11.8 of this Attachment Y that arise out of an agreement that contains a cost, premium, or fee to terminate the agreement in whole or in part prior to the anticipated RMR Start Date, or commencement of service as a Gap Solution, shall be reduced by the cost, premium or fee that would have been incurred had the Generator ceased operations on a date identified in the Generator Deactivation Notice, or such other date associated with performing service as a Gap Solution.

31.2.11.8.1.2 For each proposed demand response solution and transmission project, the ISO shall calculate the net costs that would be incurred to provide the service identified in the Developer's response to the ISO's request for Gap Solutions, considering any costs the Developer otherwise had a contractual or regulatory obligation to incur.

31.2.11.8.1.3 The ISO shall identify as "Capital Expenditures" the purchase or non-operational lease of, or modification to real property or assets (including, but not limited to, land, buildings, and equipment) that (a) are necessary to permit an Initiating Generator or Viable and Sufficient Gap Solution to provide service to satisfy, in whole or in part, the Reliability Need identified in the ISO's request for Gap Solutions, (b) have a useful life greater than one year, and (c) are not otherwise included in the ISO's calculation of RMR Avoidable Costs. The ISO shall also identify the reasonably anticipated date the Capital Expenditure will be placed into service, or otherwise integrated into the Generator.

31.2.11.8.1.4 Revenue Calculation. As a component to the ISO's calculation of the total net cost of each Initiating Generator and Viable and Sufficient Gap Solution, the ISO shall calculate the estimated revenues thereof.

31.2.11.8.1.4.1 If an Initiating Generator or other Generator that has been determined to be a Viable and Sufficient Gap Solution has a contract pursuant to which it provides energy, capacity, or ancillary services, the ISO shall also, for the period of such contract, calculate the estimated revenues for the provision of energy, capacity or ancillary services thereunder.

31.2.11.8.2 Identification of the Lowest Net Cost Non-Generation Solution. The ISO shall determine if there is a non-generator Viable and Sufficient Gap Solution that has an estimated net present value that is distinctly higher than the net present value of any Initiating Generator or Generator that is a Viable and Sufficient Gap Solution for a Reliability Need (*i.e.*, the non-generator Viable and Sufficient Gap Solution has a lower net cost). The ISO shall inform the NYSPC and post on its

website the identification of the non-generation Viable and Sufficient Gap Solution that has the highest estimated net present value, provided it is distinctly higher than the net present value of any Initiating Generator or Generator that is a Viable and Sufficient Gap Solution. That posting shall not disclose the estimated costs or revenues of any solution, nor identify which generator solution has the lowest estimated net cost.

31.2.11.8.3 The ISO shall seek comment from the Market Monitoring Unit on matters relating to the inputs and the calculations performed pursuant to Sections 31.2.11.8, and the identification of the non-generation Viable and Sufficient Gap Solution if there is one that has an estimated net present value that is distinctly higher than the net present value of any Initiating Generator or Generator that is a Viable and Sufficient Gap Solution (*i.e.*, the non-generation Viable and Sufficient Gap Solution has a lower net cost), pursuant to Section 31.2.11.8.2. The responsibilities of the Market Monitoring Unit that are addressed in this Section are also addressed in Section 31.2.11.18.1 of this Attachment Y and in Section 30.4.6.8.6 of Attachment O to the ISO Services Tariff.

**31.2.11.9 Consideration of Non-Generation Gap Solutions**

The NYPSC or other appropriate governmental agency(ies) and/or authority(ies) with jurisdiction over the implementation or siting of Gap Solutions will determine which, if any, of the non-generation Viable and Sufficient Gap Solutions submitted by the ISO will be implemented to address the identified Reliability Need. The ISO will monitor the development of any Gap Solution(s) identified by the NYPSC in accordance with ISO Procedures. The requirements concerning the NYPSC within Section 31.2.11 will apply equally with regard to

any agency or authority with jurisdiction over the implementation or siting of Gap Solutions pursuant to this Section 31.2.11.9.

**31.2.11.10 RMR Service Offers and RMR Agreements**

31.2.11.10.1 If the ISO determines that a Gap Solution is needed, the ISO may enter into an RMR Agreement if the ISO determines it is necessary to pursuant to this section. In determining whether to enter into an RMR Agreement, the ISO will consider, among other things: (i) whether the ISO identified any non-generation Viable and Sufficient Gap Solution(s) that would satisfy in whole or in part the identified Reliability Need; and (ii) whether the NYPSC (or other agency or authority with jurisdiction over the implementation or siting of Gap Solutions) has timely identified, or has elected not to identify, sufficient non-generation Gap Solutions to satisfy completely the identified Reliability Need. If, subsequent to the ISO's execution of an RMR Agreement to satisfy in whole or in part the Reliability Need, the NYPSC (or other agency or authority with jurisdiction over the implementation or siting of Gap Solutions) identifies non-generation Gap Solution(s) that would satisfy in whole or in part the Reliability Need, the ISO may withdraw its filing of, or terminate, the RMR Agreement.

31.2.11.10.2 If there is a non-generation Viable and Sufficient Gap Solution but the NYPSC (or other agency or authority with jurisdiction over the implementation or siting of Gap Solutions) has not identified it pursuant to Section 31.2.11.9 on or before the ISO determines it should proceed with an RMR Agreement to timely address the Reliability Need, then (a) if there is only one Initiating Generator or Generator that is a Viable and Sufficient Gap Solution for a Reliability Need, the

ISO shall provide to that Generator its RMR Avoidable Cost and an opportunity for it to enter into the *Form of Reliability Must Run Agreement* set forth in Appendix G of Attachment Y of the ISO OATT, and (b) if there is more than one Initiating Generator or Generator that is a Viable and Sufficient Gap Solution for a Reliability Need, the ISO shall notify each such Generator that has been determined to be a Viable and Sufficient Gap Solution that the ISO is requesting offers to provide service pursuant to an RMR Agreement.

31.2.11.10.3 The ISO shall concurrently post on its website that it has issued a request for RMR service offers.

31.2.11.10.4 The ISO's notice to each Generator of a request for RMR service offers shall include (a) the Generator's RMR Avoidable Costs determined pursuant to Section 31.2.11.8, and separately identify the Capital Expenditure amount that is included in the RMR Avoidable Costs and the reasonably anticipated date the Capital Expenditure will be placed into service, or otherwise integrated into the Generator, (b) the duration of the period for which the ISO determined the Generator was viable and sufficient to meet (in whole or in part) the Reliability Need, (c) the deadline by which offers must be received by the ISO, and (d) any other information that must be provided in the Generator's response in accordance with ISO Procedures.

31.2.11.10.5 Offers in response to a request for RMR service offers shall (a) state the price at which the Generator is willing to enter into an RMR Agreement with (i) an Availability and Performance Rate or (ii) and Owner Developed Rate for which the Generator would be seeking approval from the Commission, and

(b) separately state the anticipated timing and cost of each Capital Expenditure that is included in the offer, (c) if the *Form of Reliability Must Run Agreement* set forth in Appendix G of Attachment Y of the ISO OATT is incompatible with the Generator's ability to provide service absent a modification to a term or condition, provide a blackline marking any and all changes that are necessary to permit the Generator to provide RMR service, and explain why, absent such changes, the Generator would be unable to provide RMR service, (d) state the duration for which the Generator is being made available to provide the RMR service (which shall be no longer than the duration the ISO determined the Generator is a viable and sufficient solution,) and specify whether the offer would be the same for any shorter period of time, and (e) state whether the offer is for less than or equal to the generator's full cost of service. The offer must be executed by a duly authorized officer with authority to bind the Market Party to an RMR Agreement. The ISO will not consider offers that indicate they are for an amount greater than the Generator's full cost of service. The ISO shall exclude from consideration offers that are received after the deadline.

31.2.11.10.6 The ISO shall rank the Generators from which it received offers in accordance with Section 31.2.11.10.5 primarily based on which offer, or set of offers from more than one Generator, results in the highest net present value solution to the Reliability Need. The ISO shall also consider any blacklined modifications to the *Form of Reliability Must Run Agreement* set forth in Appendix G of Attachment Y of the ISO OATT that were submitted that the ISO reasonably projects would affect the cost. In the event that cost alone does not

provide for a clear delineation between two or more offers, the ISO shall also consider in its ranking the operational impacts and the size of the Generators in an effort to minimize impacts to markets. The ISO shall seek comment from the Market Monitoring Unit on its review and ranking of the offers. The responsibilities of the Market Monitoring Unit that are addressed in this Section are also addressed in Section 31.2.11.18.2 of this Attachment Y and in Section 30.4.6.8.6 of Attachment O of the ISO Services Tariff.

**31.2.11.11 Entry into RMR Agreements**

31.2.11.11.1 The ISO may enter into an RMR Agreement for service from one or more of the Generators from which it received offers in accordance with Sections 31.2.11.10.4 and 31.2.11.10.5 that can individually, or in conjunction with other Viable and Sufficient Gap Solutions, satisfy the identified Reliability Need. If multiple Generators are capable of satisfying in whole or in part the identified Reliability Need, the ISO may execute an RMR Agreement with the Generator, or more than one Generator that the ISO determines submitted the best offer(s) in ranking pursuant to Section 31.2.11.9.5, provided that the offer accepts the Availability and Performance Rate, does not exceed the RMR Avoidable Costs determined by the ISO, and that the amount of Capital Expenditures in any given year included in the offer do not exceed 10,000,000 U.S. Dollars if a non-nuclear Generator, and 25,000,000 U.S. Dollars if a nuclear Generator. If the offer satisfies the stated requirements, but the amount of Capital Expenditures in any given year included in the offer exceeds the applicable limit in the preceding sentence, then the ISO may accept the offer conditioned upon the Commission

approving the Capital Expenditure amount. If the offer exceeds the RMR Avoidable Costs determined by the ISO, and if there are no modifications, or only modifications which the ISO has determined are reasonable, to the *Form of Reliability Must Run Agreement* set forth in Appendix G of Attachment Y of the ISO OATT, then the ISO will identify the Generator, and the ISO and the Owner will submit filings to the Commission in accordance with Section 31.2.11.11.5. If a Generator's offer is lower than the other offers but the Generator's proposed revisions to the *Form of Reliability Must Run Agreement* are not acceptable to the ISO, then the ISO may proceed to enter into an RMR Agreement, in accordance with this section, with one or more Generator(s) that submitted the next ranked offer or offers.

31.2.11.11.2 The ISO will tender to the Owner of the selected Generator(s) the *Form of Reliability Must Run Agreement* set forth in Appendix G of Attachment Y of the ISO OATT. The term of the RMR Agreement will be determined by the ISO based on: (i) the in-service date of the conceptual permanent solution to the identified Reliability Need submitted by the Responsible Transmission Owner(s) pursuant to Section 31.2.11.3, and (ii) any modifications to the scope and timing of the identified Reliability Need resulting from circumstances as the identification by the NYPSC (or other agency or authority with jurisdiction over the implementation or siting of non-generation Gap Solutions), the ISO's identification of market-based solutions, and RMR Agreements entered into between the ISO and other Generators. If the Reliability Need is identified

pursuant to a Generator Deactivation Assessment, the effective date of the RMR Agreement shall be no earlier than the completion of the 365-day notice period.

31.2.11.11.3 Filing of Executed RMR Agreement. The ISO will submit an RMR Agreement, including a proposed Availability and Performance Rate, to the Commission pursuant to Section 205 of the Federal Power Act if the ISO and Owner agree on the terms and conditions of the RMR Agreement, Owner accepts the Availability and Performance Rate calculated by the ISO for its Generator, and the ISO and Owner execute the RMR Agreement. The ISO's filing shall specifically identify and explain any changes to the *Form of Reliability Must Run Agreement* terms and conditions that ISO and Owner have mutually agreed to.

31.2.11.11.4 Filing of Unexecuted RMR Agreement by ISO and Capital Expenditures in excess of annual limit by owner. The ISO will submit an RMR Agreement, including a proposed Availability and Performance Rate, to the Commission pursuant to Section 205 of the Federal Power Act if the ISO and Owner agree on the terms and conditions of the RMR Agreement and Owner accepts the Availability and Performance Rate calculated by the ISO for its Generator. The ISO's filing shall specifically identify and explain any changes to the *Form of Reliability Must Run Agreement* terms and conditions that ISO and Owner have mutually agreed to. Owner shall submit a filing pursuant to Section 205 of the Federal Power Act in addition to the ISO's filing of the RMR Agreement that proposes the inclusion of the costs of certain Capital Expenditures in the Availability and Performance Rate that exceed the U.S. Dollar limits specified in Section 31.2.11.11.1, which filing shall be consistent with the terms and

conditions of service proposed in the RMR Agreement that the ISO submits, and shall track the format of the RMR Agreement that the ISO submits.

31.2.11.11.5 Filing of Unexecuted RMR Agreement and Owner Developed Rate. If the ISO and Owner agree on the terms and conditions of the RMR Agreement, but Owner rejects the Availability and Performance Rate calculated by the ISO for its Generator and proposes an Owner Developed Rate, the ISO will submit an unexecuted RMR Agreement to the Commission pursuant to Section 205 of the Federal Power Act that sets forth the agreed upon terms and conditions of the RMR Agreement. The ISO's filing shall specifically identify and explain any changes to the *Form of Reliability Must Run Agreement* terms and conditions that ISO and Owner have mutually agreed to. Owner shall submit a separate filing to the Commission pursuant to Section 205 of the Federal Power Act that proposes an "Owner Developed Rate," which filing shall be consistent with the terms and conditions of service proposed in the RMR Agreement the ISO submitted and shall track the format of the RMR Agreement the ISO submitted.

31.2.11.11.16 As part of its submission of an executed RMR Agreement pursuant to Section 31.2.11.11.3 or an unexecuted RMR Agreement pursuant to Sections 31.2.11.11.4 or 31.2.11.11.5, the ISO will include: (i) a description of the methodology and results of the reliability studies that identified a Reliability Need requiring a Gap Solution, which description will specify identified violations of Reliability Criteria and local criteria and describe the impacted criteria, and (ii) a description of the alternative solutions evaluated by the ISO and why the term of the RMR Agreement is appropriate in light of these alternative solutions.

31.2.11.12 Gap Solutions proposed under Section 31.2.11.3 shall strive to be compatible with permanent market-based and regulated solutions, as applicable.

31.2.11.13 A permanent regulated solution, if appropriate, may proceed in parallel with a Gap Solution.

31.2.11.14 A Market Participant's Generator that satisfies the requirements to be Retired or enter into a Mothball Outage may be Retired or enter into a Mothball Outage, as applicable, within 365 days of: (i) the conclusion of the 365-day notice period, or (ii) the date specified in the Generator Deactivation Notice for the Generator to be Retired or enter into a Mothball Outage if the Market Participant provided greater than 365 days prior notice. If the Generator is not Retired or does not enter into a Mothball Outage within this time period, the Market Participant must submit a new Generator Deactivation Notice and satisfy anew the requirements of this Section 31.2.11.2.1 and 31.2.11.2.2 before the Generator may be Retired or enter into a Mothball Outage.

31.2.11.15 If: (i) a Market Participant rescinds its Generator Deactivation Notice, or (ii) a Market Participant's Generator has not Retired or entered into a Mothball Outage within the timeframes described in Section 31.2.11.14 and is not operating under an RMR Agreement, the Market Participant must reimburse the ISO and the Responsible Transmission Owner(s) the actual costs that each incurred in performing their responsibilities under this Section 31.2.11 in response to the Market Participant's submission of a Generator Deactivation Notice, including any costs associated with using contractors. In the event that a Market Participant rescinds its Generator Deactivation Notice before the ISO posts the results of the

Generator Deactivation Assessment conducted under Section 31.2.11.2.4, the ISO will not thereafter post the results of said assessment.

**31.2.11.16 RMR Generator Additional Costs**

31.2.11.16.1 Proposed Additional Costs. During the performance of an RMR Agreement, the Owner of one or more RMR Generators shall promptly notify the ISO of an event that (a) could not reasonably have been foreseen at the time the rate in the RMR Agreement was executed, and that (b) it reasonably expects may require it to incur costs that in the aggregate exceed the lesser of (x) $250,000, and (y) five (5) percent of the annual RMR Avoidable Costs excluding the cost of Capital Expenditures, that (i) it can reasonably demonstrate was not among the costs (A) submitted to the ISO prior to the execution of an RMR Agreement with an Availability and Performance Rate, or (B) within the categories of costs submitted to the Commission in a petition for an Owner Developed Rate, and (ii) are necessary to incur in order to for the RMR Generator to be able to continue to perform its obligations under the RMR Agreement after the event (a "Notice of Event of Proposed Additional Cost"). Following its submission of the required Notice of Event of Proposed Additional Cost, the Owner shall promptly notify the ISO of, and provide updates addressing the following: (i) the reason(s) why the expense was or must be incurred, (ii) viable alternatives to incurring the expense, (iii) actions examined or taken to avoid the need to incur the expense, and to minimize the expense, (iv) the potential impact on the RMR Generator's ability to perform its obligations under an RMR Agreement if the expense is not incurred, (v) the estimated and actual costs of the proposed expense, (vi) the plan

specifying the schedule and timing of any planned action or expenditure, (vii) an explanation and supporting documentation of how that plan compares with the Owner's past similar actions and protocols, (viii) whether each cost is associated solely with the RMR Generator or are for services or functions shared with other units or businesses; and if a shared cost, the Owner shall identify the other entities with which the cost is shared, the entity that allocates the cost to it, and accounting protocols and methodology used to allocate the units and businesses across which the cost is allocated.

31.2.11.16.1.1 If the cost of returning an RMR Generator to service does not exceed the lesser of (x) $250,000, and (y) five (5) percent of the annual RMR Avoidable Costs excluding the cost of Capital Expenditures, then the Owner shall promptly return the RMR Generator to service without additional recompense.

31.2.11.16.1.2 ISO Identification of Proposed Additional Costs. If the ISO determines that the Notice of Event of Proposed Additional Cost was timely provided and each of the requirements in Subsections (a) and (b) of Section 31.2.11.16.1 have been met, and the information required by Subsections (i) through (viii) has been provided, it shall be a "Proposed Additional Cost."

31.2.11.16.2 Proposed Additional Cost Eligibility for Recovery

31.2.11.16.2.1 The ISO shall review, verify, and/or validate the information provided by the Owner for a Proposed Additional Cost. The ISO may require the Owner to re-submit or to submit additional information to support statements and costs that the ISO determines are not adequately supported or otherwise verifiable. A "Substantiated Additional Cost" shall mean a Proposed Additional Cost that the

ISO has either verified is the actual cost, or verified and validated the estimated cost information received from the Owner, provided that (a) the Owner demonstrates it took measures to minimize the expense, or if the ISO determines that the Owner did not demonstrate it took such steps, such amount estimated by the ISO that would be the expense had the RMR Generator taken measures to reduce it, and (b) it is or was necessary for the Owner to incur these costs for the RMR Generator to perform its obligations under the RMR Agreement; provided the ISO has not issued a notice of shut-down (or similar notice) to Owner for the RMR Generator pursuant to the RMR Agreement. If the cost information provided by the Owner cannot be verified and validated by the ISO, the ISO shall substitute the amount it reasonably determines. The ISO shall also identify if the Substantiated Additional Costs, or a component thereof, is a Capital Expenditure by using the applicable criteria set forth in Section 31.2.11.8.1.3. The ISO shall notify the Owner of its determination regarding whether Proposed Additional Costs are Substantiated Additional Costs.

31.2.11.16.2.2 The ISO shall seek comment from the Market Monitoring Unit on its review of Proposed Additional Costs and determinations of Substantiated Additional Costs. The responsibilities of the Market Monitoring Unit that are addressed in this Section are also addressed in Section 31.2.11.18.1 of this Attachment Y and in Section 30.4.6.8.6 of Attachment O of the ISO Services Tariff.

31.2.11.16.3 ISO's authority to recover and pay Substantiated Additional Costs that are Capital Expenditures. This Section shall apply only to RMR Agreements with an

Availability and Performance Rate. If a Substantiated Additional Cost is determined by the ISO to be a Capital Expenditure and it does not exceed 10,000,000 U.S. Dollars if a non-nuclear Generator, or 25,000,000 U.S. Dollars if a nuclear Generator, on the basis of the total expenditure needed to address the event that resulted in the Notice of Event of Proposed Additional Cost, then the ISO may recover the Substantiated Additional Cost that is a Capital Expenditure pursuant to OATT Rate Schedule 14 and pay that amount to Owner in accordance with (a) the rules in Section 31.2.11.17 of Attachment Y that address the ISO's payment of Capital Expenditures, and (b) Rate Schedule 8 to the Services Tariff. The ISO shall submit an informational filing to the Commission identifying any Capital Expenditures it is paying pursuant to the authority granted in this section.

31.2.11.16.4 Owner may request Commission approval for recovery of additional costs. If the Owner makes such a filing, it shall also submit the ISO's determinations pursuant to Sections 31.2.11.16.1.2 and 31.2.11.16.2.1 with its filing, or promptly after receipt of either determination. The ISO shall only be obligated to pay the Owner under this section if (a) the Commission determines that the cost filed for the RMR Generator is eligible for recovery as a Proposed or Substantiated Additional Cost, and (b) the Commission approves the specific amount and authorizes its recovery. If the Proposed or Substantiated Additional Cost that the Commission authorizes payment of is for a Capital Expenditure, the ISO will pay in accordance with (a) the rules in Section 31.2.11.17 of Attachment Y that address the ISO's payment of Capital Expenditures, and (b) Rate Schedule 8 to the Services Tariff. If the Proposed or Substantiated Additional Cost that the

Commission authorizes payment of is an Avoidable Cost that is not a Capital Expenditure then payment directed by a Commission order shall be made in accordance with Rate Schedule 8 to the ISO Services Tariff.

31.2.11.17 Payment of Capital Expenditures to RMR Generators

31.2.11.17.1 Capital Expenditures that are specifically identified (including an estimated cost and estimated in-service date) in a Commission-accepted Availability and Performance Rate or in a Commission-accepted Owner Developed Rate are eligible for recovery in accordance with the rules set forth in Section 31.2.11.17 of Attachment Y, Section 23.6.5 of the ISO Services Tariff, Rate Schedule 8 of the ISO Services Tariff, Schedule 14 of the ISO OATT, and any relevant Commission order.

31.2.11.17.2 Capital Expenditures that are Proposed Additional Costs or Substantiated Additional Costs are eligible for recovery in accordance with the rules set forth in Sections 31.2.11.16 and 31.2.11.17 of Attachment Y, Section 23.6.5 of the ISO Services Tariff, Rate Schedule 8 of the ISO Services Tariff, Schedule 14 of the ISO OATT, and any relevant Commission order.

31.2.11.17.3 ISO authority to authorize Capital Expenditures. If the ISO determines that (a) Capital Expenditures are necessary for a Generator to provide service under an RMR Agreement, and (b) work on one or more of the Capital Expenditures must commence in advance of Commission action in order to timely, or more timely, address a Reliability Need, then the ISO may authorize the Owner to spend up to 10,000,000 U.S. Dollars if a non-nuclear Generator, or 25,000,000 U.S. Dollars if a nuclear Generator, in total, to develop the Capital

Expenditure(s) in advance of receiving an order from the Commission. The ISO shall submit an informational filing to the Commission identifying any Capital Expenditures it is authorizing pursuant to the authority granted in this Section. The ISO may recover the cost of such a Capital Expenditure pursuant to Schedule 14 of the ISO OATT and pay the Owner in accordance with (a) the rules in this Section 31.2.11.17, and (b) Rate Schedule 8 to the ISO Services Tariff. If the Commission issues an order rejecting the proposed Capital Expenditure, then the Owner shall cease work on the Capital Expenditure and take reasonable efforts to minimize the costs it incurs. Reimbursement of a rejected Capital Expenditure shall be limited to actual costs incurred, including reasonable wind-down costs, shall be subject to the dollar limits set forth in this section, and shall be reviewed in accordance with Section 31.2.11.17.5 below. Allowed wind-down costs shall be reimbursed as additional Avoidable Costs that are not Capital Expenditures. ISO review pursuant to Section 31.2.11.17.5 shall include consideration of whether the Owner timely ceased developing a Capital Expenditure and made reasonable efforts to minimize its wind-down costs.

31.2.11.17.4 Early termination of RMR Agreement. If the Owner is working to complete a Capital Expenditure consistent with an accepted RMR Agreement or consistent with an approved or accepted Proposed Additional Cost or Substantiated Additional Cost and the RMR Agreement is terminated early because (x) the Reliability Need is resolved sooner than expected, or (y) the RMR Generator suffers a forced outage that would require significant costs to repair, or (z) for any other reason that does not involve an uncured Owner default under the

RMR Agreement or the RMR Generator failing to satisfy one or more of the operating standards described in Sections 31.2.11.19.4(A) and (B) below, and if Owner ceased work on the Capital Expenditure and made reasonable efforts to minimize the costs it incurred, then, following review, the ISO shall recover the actual costs the Owner incurred to construct the Capital Expenditure and to wind-down its work on the Capital Expenditure pursuant to Schedule 14 of the ISO OATT and pay Owner in accordance with (a) the rules in this Section 31.2.11.17, and (b) Rate Schedule 8 to the ISO Services Tariff. Allowed wind-down costs shall be reimbursed as additional Avoidable Costs that are not Capital Expenditures. ISO review pursuant to Section 31.2.11.17.5 below shall include consideration of whether the Owner timely ceased developing a Capital Expenditure and made reasonable efforts to minimize its wind-down costs.

31.2.11.17.5 ISO Review of Actual Costs Incurred Prior to Commencing Payment. After the Owner expends money for an allowed or accepted Capital Expenditure, including expenditures that may be eligible for recovery under Sections 31.2.11.17.3 and 31.2.11.17.4 above, it shall submit to the ISO copies of original documentation of the expenditure (including the financing costs) and an explanation of any difference between the estimated amount and the actual expenditure. If Owner submits an actual total amount for a Capital Expenditure that is five (5) percent or more above (a) the estimate that was used by the ISO to develop an Availability and Performance Rate or to authorize recovery of a Substantiated Additional Cost; or (b) the estimate that was presented to the Commission to recover Capital Expenditure costs that exceed the dollar

thresholds specified in Section 31.2.11.11.1, in an Owner Developed Rate, or in a request by the Owner to recover a Proposed or Substantiated Additional Cost; or (c) an appropriate portion of the estimate provided pursuant to (a) or (b) if the Capital Expenditure was not completed plus wind-down costs (if any), then the Owner shall demonstrate to the ISO that reasonable efforts were made to expend the least amount necessary. The ISO shall review, verify and/or validate the actual expenditure provided by the Owner. The ISO may require the Owner to re-submit, information that the ISO determines is not adequately supported or otherwise verifiable. The amount due for Capital Expenditure shall be equal to the amount verified and validated by the ISO as the actual expenditure. If the ISO cannot verify and/or validate, as applicable, the information the Owner provides, or if the ISO determines that reasonable efforts were not made to expend the least amount necessary, then compensation for the Capital Expenditure shall only be due after the Owner submits its Capital Expenditure to the Commission and the Commission determines the amount to be paid.

31.2.11.17.5.1 If the Commission specified the amount that it authorized to be recovered for a particular Capital Expenditure in an order, then the ISO shall permit the Owner to recover the actual amount verified and validated by the ISO, up to the limit(s) specified in the Commission order.

31.2.11.17.6 ISO payment and recovery of authorized or accepted Capital Expenditures.

31.2.11.17.6.1 The ISO shall commence paying for Capital Expenditures as soon as practicable after (i) the capital asset that is a Capital Expenditure (a) has been

placed into service, or otherwise integrated into the Generator, or (b) was not placed into service solely due to the ISO instructing the RMR Generator to halt implementation of the Capital Expenditure, or issuing a Notice of Shut-down or terminating the RMR Agreement after costs had already been incurred; and (ii) the amount paid by the Owner is verified and /or validated, as applicable, by the ISO as described in Section 31.2.11.17.5, or is determined by the Commission.

31.2.11.17.6.2 The ISO shall implement a repayment schedule in accordance with the formula specified in Section 31.2.11.17.6.2.1 below for each Capital Expenditure that will permit the Capital Expenditure to be completely repaid by the end date specified in Section 2.2.5 of the *Form of Reliability Must Run Agreement* set forth in Appendix G of Attachment Y of the ISO OATT or by the equivalent date specified in an RMR Agreement that is not a *Form of Reliability Must Run Agreement*. If an RMR Agreement terminates prior to the end date that is specified in the RMR Agreement, then the ISO may continue repaying any Capital Expenditures the Owner remains eligible to receive until that end date.

31.2.11.17.6.2.1 Repayment schedule for Capital Expenditures.

For each Capital Expenditure *CapExMonthly Payment* is the amount that Owner is permitted to recover each month:

$$CapEx\ Monthly\ Payment = \frac{Verified\ CapEx_{g,k}}{M_{E-k}}$$

Where:

$Verified\ CapEx_{g,k}$ = the amount due for a Capital Expenditure, verified and validated by the ISO as an actual expenditure for Generator $g$.

Month $k$ is the month in which Repayment of a Capital Expenditure commences.

Month *E* is the month that includes the end date specified in Section 2.2.5 in the *Form of Reliability Must Run Agreement* or by the equivalent date specified in an RMR Agreement that is not a *Form of Reliability Must Run Agreement* for Generator *g*.

$M_{E-k}$ = the number of months from month *k* to month *E*, including month *k* and month *E*.

31.2.11.17.6.3 The ISO shall pay the Owner amounts due for Capital Expenditures as a component of RMR Avoidable Costs (for an Availability and Performance Rate) or RMR Cost (for an Owner Developed Rate) under Rate Schedule 8 to the ISO Services Tariff. The ISO shall recover the cost of Capital Expenditures from RMR LSEs in accordance with Schedule 14 to the OATT.

31.2.11.17.6.4 Unless the Commission issues an order instructing it to pay, the ISO shall not pay the cost of Capital Expenditures that Section 23.6.5.2 of the Services Tariff prohibits it from paying, even if the Capital Expenditures might otherwise be payable under the rules specified in this Attachment Y.

31.2.11.17.6.5 An Owner that recovers the cost of Capital Expenditures may be required to repay to the ISO the depreciated value of the Capital Expenditure costs it recovered before the RMR Generator at or for which the Capital Expenditure was incurred is permitted to be offered into or scheduled in the ISO Administered Markets. *See* Section 15.8.6 of Rate Schedule 8 to the Services Tariff.

### 31.2.11.18 Market Monitoring Unit Review of Determinations

31.2.11.18.1 The ISO shall seek comment from the Market Monitoring Unit when (i) making cost determinations required by Section 31.2.11.8 of this Attachment Y, (ii) identifying the non-generation Viable and Sufficient Gap Solution with the highest estimated net present value provided there is one distinctly above that of

the Initiating Generator and Generators that are Viable and Sufficient Gap Solutions, (iii) reviewing and ranking of offers to provide RMR service, (iv) reviewing Proposed Additional Costs, and (v) determining Substantiated Additional Costs.

31.2.11.18.2 If the ISO identifies a non-generation Viable and Sufficient Gap Solution with a distinctly higher net present value than a Generator in accordance with Section 31.2.11.8.2, the Market Monitoring Unit shall publish a report concurrent with the ISO's posting on its website. The report shall review the ISO's RMR Avoidable Cost Determinations for non-generation Viable and Sufficient Gap Solutions, and for Initiating Generators and Generators that are Viable and Sufficient Gap Solutions for a Reliability Need to the extent necessary to report on whether the ISO's identification of the distinctly higher net present value non-generation Viable and Sufficient Gap Solution was based on cost determinations conducted in accordance with Section 31.2.11.8.2.

31.2.11.18.3 Concurrent with the ISO filing with the Commission of an RMR Agreement pursuant to Sections 31.2.11.11.3, 31.2.11.11.4, or 31.2.11.11.5, the Market Monitoring Unit shall publish a report. The report shall review the ISO's determination of the highest net value present offer (or more than one offer if in conjunction with another generator or non-generation Viable and Sufficient Gap Solution) to provide RMR service in accordance with Section 31.2.11.10.6. In the event that cost alone did not provide for a clear delineation between two or more offers, the report shall also review the ISO's consideration the size of the Generators in an effort to minimize impacts to markets. If the agreement contains

RMR Avoidable Costs and an Availability and Performance Rate, the MMU report shall also review the inputs to and ISO's calculation of the RMR Avoidable Costs; and the Availability and Performance Rate.

31.2.11.18.4 The responsibilities of the Market Monitoring Unit that are addressed in this Section 31.2.11.18 are also addressed in Section 30.4.6.8.6 of Attachment O of the ISO Services Tariff.

**31.2.11.19 Terminating RMR Agreements**

31.2.11.19.1 Each RMR Agreement shall include an end date. RMR Agreements may incorporate a different end date for each RMR Generator that operates pursuant to the RMR Agreement.

31.2.11.19.2 RMR Agreements that include more than one RMR Generator shall permit the ISO to terminate the RMR Agreement for an RMR Generator without requiring the ISO to terminate the RMR Agreement for any or all of the other RMR Generator(s) that are operating pursuant to the same RMR Agreement.

31.2.11.19.3 The ISO shall timely terminate an RMR Agreement for an RMR Generator when that RMR Generator is no longer needed to address identified Reliability Need(s).

31.2.11.19.4 The ISO may terminate an RMR Agreement for an RMR Generator under any of the following circumstances: (A) if the RMR Generator fails to satisfy any of the minimum operating standards specified in the RMR Agreement; (B) if the RMR Generator repeatedly fails to operate as requested when it is called upon by the ISO or by a Transmission Owner to address one or more of the identified Reliability Need(s) the RMR Generator is being retained to address; (C) when the

RMR Generator suffers a forced outage that will prevent it from being available for 180 or more days to address the identified Reliability Need(s) that the RMR Generator is being retained to address; or (D) if significant Additional Costs arise (*see* Section 31.2.11.16) that make the RMR Generator more expensive than other solutions to the identified Reliability Need(s).

### 31.2.12 Confidentiality of Solutions

31.2.12.1 The term "Confidential Information" shall include all types of solutions to Reliability Needs that are submitted to the ISO as a response to Reliability Needs identified in any RNA issued by the ISO as part of the reliability planning process if the Developer of that solution designates such reliability solutions as "Confidential Information."

31.2.12.2 For regulated backstop solutions and plans submitted by the Responsible Transmission Owner in response to the findings of the RNA, the ISO shall maintain the confidentiality of same until the ISO and the Responsible Transmission Owner have agreed that the Responsible Transmission Owner has submitted viable and sufficient regulated backstop solutions and plans to meet the Reliability Needs identified in an RNA and the Responsible Transmission Owner consents to the ISO's inclusion of the proposed solution in the CRP. Thereafter, the ISO shall disclose the regulated backstop solutions and plans to the Market Participants; however, any preliminary cost estimates that may have been provided to the ISO shall not be disclosed.

31.2.12.3 For an alternative regulated response, the ISO shall determine, after consulting with the Developer thereof, whether the response would meet a

Reliability Need identified in an RNA, whether the response is viable and sufficient to meet all or part of the Reliability Need, and the Developer consents to the ISO's inclusion of the proposed solution in the CRP. Thereafter, the ISO shall disclose the alternative regulated response to the Market Participants and other interested parties; however, any preliminary cost estimates that may have been provided to the ISO shall not be disclosed.

31.2.12.4 For a market-based response, the ISO shall maintain the confidentiality of same during the reliability planning process and in the CRP, except for the following information which may be disclosed by the ISO: (i) the type of resource proposed (e.g., generation, transmission, demand side); (ii) the size of the resource expressed in megawatts of equivalent load that would be served by that resource; (iii) the subzone in which the resource would interconnect or otherwise be located; and (iv) the proposed in-service date of the resource.

31.2.12.5 In the event that the Developer of a market-based response has made a public announcement of its project or has submitted a proposal for interconnection with the ISO, the ISO shall disclose the identity of the market-based Developer and the specific project during the reliability planning process and in the CRP.

31.2.12.6 The ISO may disclose to Market Participants and other interested parties the Gap Solution and plans proposed pursuant to Section 31.2.11.3; *provided, however,* that the ISO will maintain as confidential the following information if designated as "Confidential Information": (i) a Responsible Transmission Owner's conceptual permanent solution, except for its proposed project type and

in-service date; (ii) the information required to be maintained as confidential for a market-based solution pursuant to Sections 31.2.12.4 and 31.2.12.5; and (iii) any non-public financial qualification information submitted under Section 31.2.4.1.1.1.3.

### 31.2.13 Monitoring of Reliability Project Status

31.2.13.1 The ISO will monitor and report on the status of market-based solutions to ensure their continued viability to meet Reliability Needs by the need date in the CRP. The ISO shall assess the continued viability of such projects using the following criteria:

31.2.13.1.1 Between three and five years before the Trigger Date for a regulated solution, the ISO will use a screening analysis to verify the feasibility of the proposed market-based solution (this analysis will not require final permit approvals or final contract documents).

31.2.13.1.2 Between one and two years before the Trigger Date for a regulated solution, the ISO will perform a more extensive review of the proposed market-based solution, including such elements as: status of the required interconnection studies, contract negotiations, permit applications, financing, and Site Control.

31.2.13.1.3 Less than one year before the Trigger Date of a regulated solution, the ISO will perform a detailed review of the market-based solution's status and schedule, including the status of: (1) final permits; (2) required interconnection studies; (3) the status of an interconnection agreement; (4) financing; (5) equipment; and (6) the implementation of construction schedules.

31.2.13.1.4 If the ISO, following its analysis, determines that a proposed market-based solution is no longer viable to meet the Reliability Need, the proposed market-based solution will be removed from the list of potential market-based solutions.

31.2.13.2 The ISO will monitor and report on the status of regulated solutions to ensure their continued viability to meet Reliability Needs by the need date in the CRP. The ISO shall assess the continued viability of regulated solutions using the following criteria:

31.2.13.2.1 Between three and five years before the Trigger Date for the regulated solution, the ISO will use a screening analysis to verify the feasibility of the regulated solution.

31.2.13.2.2 Between one and two years before the Trigger Date for the regulated solution, the ISO will perform a more extensive review of the proposed regulated solution, including such elements as: the status of the required interconnection studies, contract negotiations, permit applications, financing, and Site Control.

31.2.13.2.3 Less than one year before the Trigger Date for the regulated solution, the ISO will perform a detailed review of the regulated solution's status, including the status of: (1) final permits; (2) required interconnection studies; (3) the status of an interconnection agreement; (4) financing; (5) equipment; and (6) the implementation of construction schedules.

31.2.13.2.4 Prior to making a determination about the viability of a regulated solution, the ISO will communicate its intended determination to the project sponsor along with the basis for its intended determination, and will provide the sponsor a reasonable period (not more than two weeks) to respond to the ISO's intended

determination, including an opportunity to provide additional information to the ISO to support the continued viability of the proposed regulated solution. If the ISO, following its analysis, determines that a proposed regulated solution is no longer viable to meet the Reliability Need, the proposed regulated solution will be removed from the list of potential regulated solutions.

## 31.5 Cost Allocation and Cost Recovery

### 31.5.1 The Scope of Attachment Y Cost Allocation

#### 31.5.1.1 Regulated Responses

The cost allocation principles and methodologies in this Attachment Y cover regulated transmission solutions to Reliability Needs, Generators operating under an RMR Agreement as a Gap Solution to Reliability Needs, regulated transmission responses to congestion identified in the CARIS, and regulated Public Policy Transmission Projects whether proposed by a Responsible Transmission Owner or a Transmission Owner or Other Developer. The cost allocation principles and methodology for: (i) regulated transmission solutions to Reliability Needs or Generators operating under an RMR Agreement are contained in Sections 31.5.3.1 and 31.5.3.2 of this Attachment Y, (ii) regulated transmission responses to congestion identified in the CARIS are contained in Sections 31.5.4.1 and 31.5.4.2 of this Attachment Y, and (iii) regulated Public Policy Transmission Projects are contained in Sections 31.5.5 and 31.5.6 of this Attachment Y.

#### 31.5.1.2 Market-Based Responses

The cost allocation principles and methodologies in this Attachment Y do not apply to market-based solutions to Reliability Needs, to market-based responses to congestion identified in the CARIS, or to Other Public Policy Projects. The cost of a market-based project shall be the responsibility of the developer of that project.

#### 31.5.1.3 Interconnection Cost Allocation

The cost allocation principles and methodologies in this Attachment Y do not apply to the interconnection costs of generation and merchant transmission projects. Interconnection costs are determined and allocated in accordance with Attachment S, Attachment X and Attachment Z

of the ISO OATT. Costs related to the deliverability of a resource will be addressed under the ISO's deliverability procedures in Attachment S of the ISO OATT.

#### 31.5.1.4 Individual Transmission Service Requests

The cost allocation principles and methodologies in this Attachment Y do not apply to the cost of transmission expansion projects undertaken in connection with an individual request for Transmission Service. The cost of such a project is determined and allocated in accordance with Section 3.7 or Section 4.5 of the ISO OATT.

#### 31.5.1.5 LTP Facilities

The cost allocation principles and methodologies in this Attachment Y do not apply to the cost of transmission projects included in LTPs or LTP updates. Each Transmission Owner will recover the cost of such transmission projects in accordance with its then existing rate recovery mechanisms.

#### 31.5.1.6 Regulated Non-Transmission Projects

With the exception of Generators operating under an RMR Agreement as a Gap Solution to a Reliability Need, costs related to regulated non-transmission projects will be recovered by Responsible Transmission Owners, Transmission Owners and Other Developers in accordance with the provisions of New York Public Service Law, New York Public Authorities Law, or other applicable state law. Nothing in this section shall affect the Commission's jurisdiction over the sale and transmission of electric energy subject to the jurisdiction of the Commission.

#### 31.5.1.7 Eligibility for Cost Allocation and Cost Recovery

Any entity, whether a Responsible Transmission Owner, Other Developer, or Transmission Owner, shall be eligible for cost allocation and cost recovery as set forth in Section

31.5 of this Attachment Y and associated rate schedules, as applicable, for any transmission project proposed to satisfy an identified Reliability Need, Generator operating under an RMR Agreement as a Gap Solution to a Reliability Need, regulated economic transmission project, or Public Policy Transmission Project that is determined by the ISO to be eligible under Sections 31.2, 31.3, or 31.4, as applicable. Interregional Transmission Projects identified in accordance with the Interregional Planning Protocol, and that have been accepted in each region's planning process, shall be eligible for interregional cost allocation and cost recovery, as set forth in Section 31.5 of this Attachment Y and associated rate schedules. The ISO's share of the cost of an Interregional Transmission Project selected pursuant to this Attachment Y to meet a Reliability Need, congestion identified in the CARIS, or a Public Policy Transmission Need shall be eligible for cost allocation consistent with the cost allocation methodology applicable to the type of regional transmission project that would be replaced through the construction of such Interregional Transmission Project.

**31.5.2 Cost Allocation Principles Required Under Order No. 1000**

31.5.2.1 In compliance with Commission Order No. 1000, the ISO shall implement the specific cost allocation methodology in Section 31.5.3.2, 31.5.4.4, and 31.5.5.4 in accordance with the following Regional Cost Allocation Principles ("Order No. 1000 Regional Cost Allocation Principles"):

**Regional Cost Allocation Principle 1:** The ISO shall allocate the cost of transmission facilities to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits. In determining the beneficiaries of transmission facilities, the ISO's CSPP will consider benefits including, but not limited to, the

extent to which transmission facilities, individually or in the aggregate provide for maintaining reliability and sharing reserves, production cost savings and congestion relief, and/or meeting Public Policy Requirements.

**Regional Cost Allocation Principle 2:** The ISO shall not involuntarily allocate any of the costs of transmission facilities to those that receive no benefit from transmission facilities.

**Regional Cost Allocation Principle 3:** In the event that the ISO adopts a benefit to cost threshold in its CSPP to determine which transmission facilities have sufficient net benefits to be selected in a regional transmission plan for the purpose of cost allocation, such benefit to cost threshold will not be so high that transmission facilities with significant positive net benefits are excluded from cost allocation. If the ISO chooses to adopt such a threshold in its CSPP it will not include a ratio of benefits to costs that exceeds 1.25 unless the ISO justifies and the Commission approves a higher ratio.

**Regional Cost Allocation Principle 4:** The ISO's allocation method for the cost of a transmission facility selected pursuant to the process in the CSPP shall allocate costs solely within the ISO's transmission planning region unless another entity outside the region or another transmission planning region voluntarily agrees to assume a portion of those costs. Costs for an Interregional Transmission Project must be assigned only to regions in which the facility is physically located. Costs cannot be assigned involuntarily to another region. The ISO shall not bear the costs of required upgrades in another region.

**Regional Cost Allocation Principle 5:** The ISO's cost allocation method and data requirements for determining benefits and identifying beneficiaries for a transmission facility shall be transparent with adequate documentation to allow a stakeholder to determine how they were applied to a proposed transmission facility, as consistent with confidentiality requirements set forth in this Attachment Y and the ISO Code of Conduct in Attachment F of the OATT.

**Regional Cost Allocation Principle 6:** The ISO's CSPP provides a different cost allocation method for different types of transmission facilities in the regional transmission plan and each cost allocation method is set out clearly and explained in detail in this Section 31.5.

31.5.2.2 In compliance with Commission Order No. 1000, the ISO shall implement the specific cost allocation methodology in Section 31.5.7 of this Attachment Y in accordance with the following Interregional Cost Allocation Principles:

**Interregional Cost Allocation Principle 1:** The ISO shall allocate the cost of new Interregional Transmission Projects to each region in which an Interregional Transmission Project is located in a manner that is at least roughly commensurate with estimated benefits of the Interregional Transmission Project in each of the regions. In determining the beneficiaries of Interregional Transmission Projects, the ISO will consider benefits including, but not limited to, those associated with maintaining reliability and sharing reserves, production cost savings and congestion relief, and meeting Public Policy Requirements.

**Interregional Cost Allocation Principle 2:** The ISO shall not involuntarily allocate any of the costs of an Interregional Transmission Project to a region that

receives no benefit from an Interregional Transmission Project that is located in that region, either at present or in a likely future scenario.

**Interregional Cost Allocation Principle 3**: In the event that the ISO adopts a benefit-cost threshold ratio to determine whether an Interregional Transmission Project has sufficient net benefits to qualify for interregional cost allocation, this ratio shall not be so large as to exclude an Interregional Transmission Project with significant positive net benefits from cost allocation. If the ISO chooses to adopt such a threshold, they will not include a ratio of benefits to costs that exceeds 1.25 unless the Parties justify and the Commission approves a higher ratio.

**Interregional Cost Allocation Principle 4:** The ISO's allocation of costs for an Interregional Transmission Project shall be assigned only to regions in which the Interregional Transmission Project is located. The ISO shall not assign costs involuntarily to a region in which that Interregional Transmission Project is not located. The ISO shall, however, identify consequences for other regions, such as upgrades that may be required in a third region. The ISO's interregional cost allocation methodology includes provisions for allocating the costs of upgrades among the beneficiaries in the region in which the Interregional Transmission Project is located to the transmission providers in such region that agree to bear the costs associated with such upgrades.

**Interregional Cost Allocation Principle 5:** The ISO's cost allocation methodology and data requirements for determining benefits and identifying beneficiaries for an Interregional Transmission Project shall be transparent with adequate documentation to allow a stakeholder to determine how they were

applied to a proposed Interregional Transmission Project, as consistent with the confidentiality requirements set forth in this Attachment Y and the ISO Code of Conduct in Attachment F of the OATT.

**Interregional Cost Allocation Principle 6:** Though Order No. 1000 allows the ISO to provide a different cost allocation methodology for different types of interregional transmission facilities, such as facilities needed for reliability, congestion relief, or to achieve Public Policy Requirements, the ISO has chosen to adopt one interregional cost allocation methodology for all Interregional Transmission Planning Projects. The interregional cost allocation methodology is set out clearly and explained in detail in Section 31.5.7 of this Attachment Y. The share of the cost related to any Interregional Transmission Project assigned to the ISO shall be allocated as described in Section 31.5.7.1.

### 31.5.3 Regulated Responses to Reliability Needs

#### 31.5.3.1 Cost Allocation Principles

The ISO shall implement the specific cost allocation methodology in Section 31.5.3.2 of this Attachment Y in accordance with the Order No. 1000 Regional Cost Allocation Principles as set forth in Section 31.5.2.1. This methodology shall apply to cost allocation for: (i) a regulated transmission solution to an identified Reliability Need, including the ISO's share of the costs of an Interregional Transmission Project proposed as a regulated transmission solution to an identified Reliability Need allocated in accordance with Section 31.5.7 of this Attachment Y, and (ii) a Generator operating under an RMR Agreement as a Gap Solution to an identified Reliability Need.

The specific cost allocation methodology in Section 31.5.3.2 incorporates the following elements:

31.5.3.1.1 The focus of the cost allocation methodology shall be on solutions to Reliability Needs.

31.5.3.1.2 Potential impacts unrelated to addressing the Reliability Needs shall not be considered for the purpose of cost allocation for regulated solutions.

31.5.3.1.3 Primary beneficiaries shall initially be those Load Zones or Subzones identified as contributing to the reliability violation.

31.5.3.1.4 The cost allocation among primary beneficiaries shall be based upon their relative contribution to the need for the regulated solution.

31.5.3.1.5 The ISO will examine the development of specific cost allocation rules based on the nature of the reliability violation (*e.g.*, thermal overload, voltage, stability, resource adequacy and short circuit).

31.5.3.1.6 Cost allocation shall recognize the terms of prior agreements among the Transmission Owners, if applicable.

31.5.3.1.7 Consideration should be given to the use of a materiality threshold for cost allocation purposes.

31.5.3.1.8 The methodology shall provide for ease of implementation and administration to minimize debate and delays to the extent possible.

31.5.3.1.9 Consideration should be given to the “free rider” issue as appropriate. The methodology shall be fair and equitable.

31.5.3.1.10 The methodology shall provide cost recovery certainty to investors to the extent possible.

31.5.3.1.11 The methodology shall apply, to the extent possible, to Gap Solutions.

31.5.3.1.12 Cost allocation is independent of the actual triggered project(s), except when allocating cost responsibilities associated with meeting a Locational Minimum Installed Capacity Requirement ("LCR"), and is based on a separate process that results in NYCA meeting its LOLE requirement.

31.5.3.1.13 Cost allocation for a solution that meets the needs of a Target Year assumes that backstop solutions of prior years have been implemented.

31.5.3.1.14 Cost allocation will consider the most recent values for LCRs. LCRs must be met for the Target Year.

**31.5.3.2 Cost Allocation Methodology**

The cost allocation mechanism under this Section 31.5.3.2 sets forth the basis for allocating costs associated with: (i) a Responsible Transmission Owner's regulated backstop solution or its transmission solution identified pursuant to Section 31.2.11.9 as a Gap Solution to be implemented to address a Reliability Need, (ii) an Other Developer's or Transmission Owner's alternative regulated transmission solution selected by the ISO as the more efficient or cost-effective transmission solution to an identified Reliability Need or identified pursuant to Section 31.2.11.9 as a Gap Solution to be implemented to address a Reliability Need, or (iii) a Generator operating under an RMR Agreement as a Gap Solution to an identified Reliability Need.

The formula is not applicable to that portion of a project beyond the size of the solution needed to provide the more efficient or cost effective solution appropriate to the Reliability Need identified in the RNA. Nor is the formula applicable to that portion of the cost of a regulated transmission reliability project that is, pursuant to Section 25.7.12 of Attachment S to the ISO

OATT, paid for with funds previously committed by or collected from Developers for the installation of System Deliverability Upgrades required for the interconnection of generation or merchant transmission projects.

This Section 31.5.3.2 establishes the allocation of the costs related to resolving Reliability Needs resulting from resource adequacy, BPTF thermal transmission security, local transmission security, dynamic stability, and short circuit issues. Costs will be allocated in accordance with the following hierarchy: (i) resource adequacy pursuant to Section 31.5.3.2.1, (ii) BPTF thermal transmission security pursuant to Section 31.5.3.2.2, (iii) BPTF voltage security pursuant to Section 31.5.3.2.3, (iv) local transmission security pursuant to Section 31.5.3.2.4, (v) dynamic stability pursuant to Section 31.5.3.2.5, and (vi) short circuit pursuant to Section 31.5.3.2.6.

**31.5.3.2.1 Resource Adequacy Reliability Solution Cost Allocation Formula**

For purposes of solutions eligible for cost allocation under this Section 31.5.3.2, this section sets forth the cost allocation methodology applicable to that portion of the costs of the solution attributable to resolving resource adequacy. The same cost allocation formula is applied regardless of the project or sets of projects being triggered; however, the nature of the solution set may lead to some terms equaling zero, thereby dropping out of the equation. To ensure that appropriate allocation to the LCR and non-LCR zones occurs, the zonal allocation percentages are developed through a series of steps that first identify responsibility for LCR deficiencies, followed by responsibility for remaining need. The following formula shall apply to the allocation of the costs of the solution attributable to resource adequacy:

$$\text{Resource Adequacy Cost Allocation}_i = \left[ \frac{\text{LCRdef}_i}{} + \left( \frac{\text{Concident Peak}_i}{*\,(1 + \text{IRM} - \text{LCR}_i)} * \text{Soln STWdef} \right) \right.$$

$$\frac{\text{Soln Size}}{\dfrac{\sum_{k=1}^{n} \text{Coincident Peak}_k * (1 + \text{IRM} - \text{LCR}_k)}{\text{Soln Size}} + \left( \dfrac{\text{Concident Peak}_i * (1 + \text{IRM} - \text{LCR}_i)}{\sum_{l=1}^{m} \text{Coincident Peak}_l * (1 + \text{IRM} - \text{LCR}_l)} * \dfrac{\text{Soln Cldef}}{\text{Soln Size}} \right)} * 100\%$$

Where *i* is for each applicable zone, *n* represent the total zones in NYCA, *m* represents the zones isolated by the binding interfaces, IRM is the statewide reserve margin, and where LCR is defined as the locational capacity requirement in terms of percentage and is equal to zero for those zones without an LCR requirement, $LCRdef_i$ is the applicable zonal LCR deficiency, SolnSTWdef is the STWdef for each applicable project, SolnCIdef is the CIdef for each applicable project, and Soln_Size represents the total compensatory MW addressed by each applicable project for all reliability cost allocation steps in this Section 31.5.3.2.

Three step cost allocation methodology for regulated reliability solutions:

31.5.3.2.1.1 Step 1 - LCR Deficiency

31.5.3.2.1.1.1 Any deficiencies in meeting the LCRs for the Target Year will be referred to as the LCRdef. If the reliability criterion is met once the LCR deficiencies have been addressed, that is LOLE ≤ 0.1 for the Target Year is achieved, then the only costs allocated will be those related to the LCRdef MW. Cost responsibility for the LCRdef MW will be borne by each deficient locational zone(s), to the extent each is individually deficient.

For a single solution that addresses only an LCR deficiency in the applicable LCR zone, the equation would reduce to:

$$\text{Allocation}_i = \frac{\text{LCRdef}_i}{\text{Soln\_Size}} * 100\%$$

Where *i* is for each applicable LCR zone, $LCRdef_i$ represents the applicable zonal LCR deficiency, and Soln_Size represents the total compensatory MW addressed by the applicable project.

31.5.3.2.1.1.2 Prior to the LOLE calculation, voltage constrained interfaces will be recalculated to determine the resulting transfer limits when the LCRdef MW are added.

31.5.3.2.1.2 Step 2 - Statewide Resource Deficiency. If the reliability criterion is not met after the LCRdef has been addressed, that is an LOLE > 0.1, then a NYCA Free Flow Test will be conducted to determine if NYCA has sufficient resources to meet an LOLE of 0.1.

31.5.3.2.1.2.1 If NYCA is found to be resource limited, the ISO, using the transfer limits and resources determined in Step 1, will determine the optimal distribution of additional resources to achieve a reduction in the NYCA LOLE to 0.1.

31.5.3.2.1.2.2 Cost allocation for compensatory MW added for cost allocation purposes to achieve an LOLE of 0.1, defined as a Statewide MW deficiency (STWdef), will be prorated to all NYCA zones, based on the NYCA coincident peak load. The allocation to locational zones will take into account their locational requirements. For a single solution that addresses only a statewide deficiency, the equation would reduce to:

$$\text{Allocation}_i = \left[ \frac{\text{Concident Peak}_i * (1 + \text{IRM} - \text{LCR}_i)}{\sum_{k=1}^{n} \text{Coincident Peak}_k * (1 + \text{IRM} - \text{LCR}_k)} * \frac{\text{Soln STWdef}}{\text{Soln Size}} \right] *100\%$$

Where *i* is for each applicable zone, *n* is for the total zones in NYCA, IRM is the statewide reserve margin, and LCR is defined as the locational capacity

requirement in terms of percentage and is equal to zero for those zones without an LCR requirement, Soln STWdef is the STWdef for the applicable project, and Soln_Size represents the total compensatory MW addressed by the applicable project.

31.5.3.2.1.3 Step 3 - Constrained Interface Deficiency. If the NYCA is not resource limited as determined by the NYCA Free Flow Test, then the ISO will examine constrained transmission interfaces, using the Binding Interface Test.

31.5.3.2.1.3.1 The ISO will provide output results of the reliability simulation program utilized for the RNA that indicate the hours that each interface is at limit in each flow direction, as well as the hours that coincide with a loss of load event. These values will be used as an initial indicator to determine the binding interfaces that are impacting LOLE within the NYCA.

31.5.3.2.1.3.2 The ISO will review the output of the reliability simulation program utilized for the RNA along with other applicable information that may be available to make the determination of the binding interfaces.

31.5.3.2.1.3.3 Bounded Regions are assigned cost responsibility for the compensatory MW, defined as CIdef, needed to reach an LOLE of 0.1.

31.5.3.2.1.3.4 If one or more Bounded Regions are isolated as a result of binding interfaces identified through the Binding Interface Test, the ISO will determine the optimal distribution of compensatory MW to achieve a NYCA LOLE of 0.1. Compensatory MW will be added until the required NYCA LOLE is achieved.

31.5.3.2.1.3.5 The Bounded Regions will be identified by the ISO's Binding Interface Test, which identifies the bounded interface limits that can be relieved and have

the greatest impact on NYCA LOLE. The Bounded Region that will have the greatest benefit to NYCA LOLE will be the area to be first allocated costs in this step. The ISO will determine if after the first addition of compensating MWs the Bounded Region with the greatest impact on LOLE has changed. During this iterative process, the Binding Interface Test will look across the state to identify the appropriate Bounded Region. Specifically, the Binding Interface Test will be applied starting from the interface that has the greatest benefit to LOLE (the greatest LOLE reduction per interface compensatory MW addition), and then extended to subsequent interfaces until a NYCA LOLE of 0.1 is achieved.

31.5.3.2.1.3.6 The CIdef MW are allocated to the applicable Bounded Region isolated as a result of the constrained interface limits, based on their NYCA coincident peaks. Allocation to locational zones will take into account their locational requirements. For a single solution that addresses only a binding interface deficiency, the equation would reduce to:

$$\text{Allocation}_i = \left[ \frac{\text{Concident Peak}_i * (1 + \text{IRM} - \text{LCR}_\text{i})}{\sum_{l=1}^{m} \text{Coincident Peak}_l * (1 + \text{IRM} - \text{LCR}_\text{l})} * \frac{\text{SolnCIdef}}{\text{Soln Size}} \right] *100\%$$

Where *i* is for each applicable zone, *m* is for the zones isolated by the binding interfaces, IRM is the statewide reserve margin, and where LCR is defined as the locational capacity requirement in terms of percentage and is equal to zero for those zones without an LCR requirement, SolnCIdef is the CIdef for the applicable project and Soln_Size represents the total compensatory MW addressed by the applicable project.

**31.5.3.2.2 BPTF Thermal Transmission Security Cost Allocation Formula**

For purposes of solutions eligible for cost allocation under this Section 31.5.3.2, this section sets forth the cost allocation methodology applicable to that portion of the costs of the solution attributable to resolving BPTF thermal transmission security issues. If, after consideration of the compensatory MW identified in the resource adequacy reliability solution cost allocation in accordance with Section 31.5.3.2.1, there remains a BPTF thermal transmission security issue, the ISO will allocate the costs of the portion of the solution attributable to resolving the BPTF thermal transmission security issue(s) to the Subzones that contribute to the BPTF thermal transmission security issue(s) in the following manner.

31.5.3.2.2.1 Calculation of Nodal Distribution Factors. The ISO will calculate the nodal distribution factor for each load bus modeled in the power flow case utilizing the output of the reliability simulation program that identified the Reliability Need, including the NYCA generation dispatch and NYCA coincident peak Load. The nodal distribution factor represents the percentage of the Load that flows across the facility subject to the Reliability Need. The sign (positive or negative) of the nodal distribution factor represents the direction of flow.

31.5.3.2.2.2 Calculation of Nodal Flow. The ISO will calculate the nodal megawatt flow, defined as Nodal Flow, for each load bus modeled in the power flow case by multiplying the amount of Load in megawatts for the bus, defined as Nodal Load, by the nodal distribution factor for the bus. Nodal Flow represents the number of megawatts that flow across the facility subject to the Reliability Need due to the Load.

31.5.3.2.2.3 Calculation of Contributing Load and Contributing Flow. The Nodal Load for a load bus with a positive nodal distribution factor is a contributing

Load, defined as CLoad, and the Nodal Flow for that Load is contributing flow, defined as CFlow. To identify contributing Loads that have a material impact on the Reliability Need, the ISO will calculate a contributing materiality threshold, defined as CMT, as follows:

$$CMT = \frac{\sum_{k=1}^{m}\sum_{Lk=1}^{n} CFlow_{Lk}}{\sum_{k=1}^{m}\sum_{Lk=1}^{n} CLoad_{Lk}}$$

Where *m* is for the total number of Subzones and *n* is for the total number of load buses in a given Subzone.

31.5.3.2.2.4 Calculation of Helping Load and Helping Flow. The Nodal Load for a load bus with a negative or zero nodal distribution factor is a helping Load, defined as HLoad, and the Nodal Flow for that Load is helping flow, defined as HFlow. To identify helping Loads that have a material impact on the Reliability Need, the ISO will calculate a helping materiality threshold, defined as HMT, as follows:

$$HMT = \frac{\sum_{k=1}^{m}\sum_{Lk=1}^{n} HFlow_{Lk}}{\sum_{k=1}^{m}\sum_{Lk=1}^{n} HLoad_{Lk}}$$

Where *m* is for the total number of Subzones and *n* is for the total number of load buses in a given Subzone.

31.5.3.2.2.5 Calculation of Net Material Flow for Each Subzone. The ISO will identify material Nodal Flow for each Subzone and calculate the net material flow for each Subzone. For each load bus, the Nodal Flow will be identified as material flow, defined as MFlow, if the nodal distribution factor is (i) greater than or equal to CMT, or (ii) less than or equal to HMT. The net material flow for each Subzone, defined as SZ_NetFlow, is calculated as follows:

$$SZ\_NetFlow_j = \sum_{Lj=1}^{n} MFlow_{Lj}$$

Where *j* is for each Subzone and *n* is for the total number of load buses in a given Subzone.

31.5.3.2.2.6 Identification of Allocated Flow for Each Subzone. The ISO will identify the allocated flow for each Subzone and verify that sufficient contributing flow is being allocated costs. For each Subzone, if the SZ_NetFlow is greater than zero, that Subzone has a net material contribution to the Reliability Need and the SZ_NetFlow is identified as allocated flow, defined as SZ_AllocFlow. If the SZ_NetFlow is less than or equal to zero, that Subzone does not have a net material contribution to the Reliability Need and the SZ_AllocFlow is zero for that Subzone. If the total SZ_AllocFlow for all Subzones is less than 60% of the total CFlow for all Subzones, then the CMT will be reduced and SZ_NetFlow recalculated until the total SZ_AllocFlow for all Subzones is at least 60% of the total CFlow for all Subzones.

31.5.3.2.2.7 Cost Allocation for a Single BPTF Thermal Transmission Security Issue. For a single solution that addresses only a BPTF thermal transmission security issue, the equation for cost allocation would reduce to:

$$BPTF\ Thermal\ Cost\ Alloction_j = \frac{SZ\_AllocFlow_j}{\sum_{k=1}^{m} SZ\_AllocFlow_k} \times \frac{SolnBTSdef}{Soln\_Size}$$

Where *j* is for each Subzone; *m* is for the total number of Subzones; SZ_AllocFlow is the allocated flow for each Subzone; SolnBTSdef is the number of compensatory MW for the BPTF thermal transmission security issue for the

applicable project; and Soln_Size represents the total compensatory MW addressed by the applicable project.

31.5.3.2.2.8 Cost Allocation for Multiple BPTF Thermal Transmission Security Issues. If a single solution addresses multiple BPTF thermal transmission security issues, the ISO will calculate weighting factors based on the ratio of the present value of the estimated costs for individual solutions to each BPTF thermal transmission security issue. The present values of the estimated costs for the individual solutions shall be based on a common base date that will be the beginning of the calendar month in which the cost allocation analysis is performed (the "Base Date"). The ISO will apply the weighting factors to the cost allocation calculated for each Subzone for each individual BPTF thermal transmission security issue. The following example illustrates the cost allocation for such a solution:

- A cost allocation analysis for the selected solution is to be performed during a given month establishing the beginning of that month as the Base Date.
- The ISO has identified two BPTF thermal transmission security issues, Overload X and Overload Y, and the ISO has selected a single solution (Project Z) to address both BPTF thermal transmission security issues.
- The cost of a solution to address only Overload X (Project X) is Cost(X), provided in a given year's dollars. The number of years from the Base Date to the year associated with the cost estimate of Project (X) is N(X).
- The cost of a solution to address only Overload Y (Project Y) is Cost(Y), provided in a given year's dollars. The number of years from the Base Date to the year associated with the cost estimate of Project Y is N(Y).

- The discount rate, D, to be used for the present value analysis shall be the current after-tax weighted average cost of capital for the Transmission Owners.
- Based on the foregoing assumptions, the following formulas will be used:
  - Present Value of Cost (X) = PV Cost (X) = Cost (X) / $(1+D)^{N(X)}$
  - Present Value of Cost (Y) = PV Cost (Y) = Cost (Y) / $(1+D)^{N(Y)}$
  - Overload X weighting factor = PV Cost (X)/[PV Cost (X) + PV Cost (Y)]
  - Overload Y weighting factor = PV Cost (Y)/[PV Cost (X) + PV Cost (Y)]
- Applying those formulas, if:

  Cost (X) = $100 Million and N(X) = 6.25 years

  Cost (Y) = $25 Million and N(Y) = 4.75 years

  D = 7.5% per year

  Then:

  PV Cost (X) = $100/(1+0.075)^{6.25}$ = 63.635 Million

  PV Cost (Y) = $25/(1+0.075)^{4.75}$ = 17.732 Million

  Overload X weighting factor = 63.635 / (63.635 + 17.732) = 78.21%

  Overload Y weighting factor = 17.732 / (63.635 + 17.732) = 21.79%
- Applying those weighing factors, if:

  Subzone A cost allocation for Overload X is 15%

  Subzone A cost allocation for Overload Y is 70%

  Then:

  Subzone A cost allocation % for Project Z =

  (15% * 78.21%) + (70% * 21.79%) = 26.99%

31.5.3.2.2.9 Exclusion of Subzone(s) Based on De Minimis Impact. If a Subzone is assigned a BPTF thermal transmission security cost allocation less than a *de minimis* dollar threshold of the total project costs, that Subzone will not be allocated costs; *provided however,* that the total *de minimis* Subzones may not exceed 10% of the total BPTF thermal transmission security cost allocation. The *de minimis* threshold is initially $10,000. If the total allocation percentage of all *de minimis* Subzones is greater than 10%, then the *de minimis* threshold will be reduced until the total allocation percentage of all *de minimis* Subzones is less than or equal to 10%.

**31.5.3.2.3 BPTF Voltage Security Cost Allocation**

If, after consideration of the compensatory MW identified in the resource adequacy cost allocation in accordance with Section 31.5.3.2.1 and BPTF thermal transmission security cost allocation in accordance with Section 31.5.3.2.2, there remains a BPTF voltage security issue, the ISO will allocate the costs of the portion of the solution attributable to resolving the BPTF voltage security issue(s) to the Subzones that contribute to the BPTF voltage security issue(s). The cost responsibility for the portion (MW or MVAr) of the solution attributable to resolving the BPTF voltage security issue(s), defined as SolnBVSdef, will be allocated on a Load-ratio share to each Subzone to which each bus with a voltage issue is connected, as follows:

$$BPTF\ Voltage\ Cost\ Alloction_j = \frac{Coincident\ Peak_j}{\sum_{k=1}^{m} Coincident\ Peak_k} \times \frac{SolnBVSdef}{Soln\_Size}$$

Where *j* is for each Subzone; *m* is for the total number of Subzones that are subject to BPTF voltage cost allocation; Coincident Peak is for the total peak Load for each Subzone; SolnBVSdef is for the portion of the solution necessary to resolve the BPTF voltage security

issue(s); and Soln_Size represents the total compensatory MW addressed by the applicable project.

#### 31.5.3.2.4 Local Transmission Security Cost Allocation

If, after consideration of the compensatory MW identified in the resource adequacy cost allocation in accordance with Section 31.5.3.2.1, the BPTF thermal transmission security cost allocation in accordance with Section 31.5.3.2.2, and BPTF voltage security cost allocation in accordance with Section 31.5.3.2.3, there remains a non-BPTF thermal security issue or a non-BPTF voltage security issue and the solution is an RMR Agreement, the ISO will allocate the costs of resolving the local security issue(s) to the Subzones that contribute to the local security issue(s).

31.5.3.2.4.1 The Subzone in which the receiving terminal of the non-BPTF facility is located is assigned cost responsibility for the megawatt portion of the RMR Agreement needed to eliminate the non-BPTF thermal issue(s), defined as LocalThermalMW. If multiple non-BPTF thermal issues in multiple Subzones are addressed by the RMR Agreement, the LocalThermalMW will be allocated on a Load-ratio share to each identified Subzone as follows:

$$Local\ Thermal\ Cost\ Alloction_j = \frac{Coincident\ Peak_j}{\sum_{k=1}^{m} Coincident\ Peak_k} \times \frac{LocalThermalMW}{Soln\_Size}$$

Where *j* is for each Subzone; *m* is for the total number of Subzones that are subject to local thermal cost allocation; Coincident Peak is for the total peak load for each Subzone; LocalThermalMW is for the megawatt portion of the RMR Agreement needed to eliminate the non-BPTF thermal issue(s); and Soln_Size represents the total compensatory MW addressed by the RMR Agreement.

31.5.3.2.4.2 If there remains a voltage issue after consideration of LocalThermalMW, then the cost responsibility for the megawatt portion of the RMR Agreement necessary to resolve the voltage issue(s), defined as LocalVoltageMW, will be allocated on a Load-ratio share to each Subzone to which each bus with a voltage issue is connected, as follows:

$$Local\ Voltage\ Cost\ Alloction_j = \frac{Coincident\ Peak_j}{\sum_{k=1}^{m} Coincident\ Peak_k} \times \frac{LocalVoltageMW}{Soln\_Size}$$

Where *j* is for each Subzone; *m* is for the total number of Subzones that are subject to local voltage cost allocation; Coincident Peak is for the total peak Load for each Subzone; LocalVoltageMW is for the megawatt portion of the RMR Agreement necessary to resolve the voltage issue(s); and Soln_Size represents the total compensatory MW addressed by the RMR Agreement.

**31.5.3.2.5 Dynamic Stability Cost Allocation**

If, after consideration of the compensatory MW identified in the resource adequacy cost allocation in accordance with Section 31.5.3.2.1, BPTF thermal transmission security cost allocation in accordance with Section 31.5.3.2.2, BPTF voltage security cost allocation in accordance with Section 31.5.3.2.3, and local transmission security cost allocation in accordance with Section 31.5.3.2.4, there remains a dynamic stability issue, the ISO will allocate the costs of the portion of the solution attributable to resolving the dynamic stability issue(s) to all Subzones in the NYCA on a Load-ratio share basis, as follows:

$$Dynamic\ Stability\ Cost\ Alloction_j = \frac{Coincident\ Peak_j}{\sum_{k=1}^{m} Coincident\ Peak_k} \times \frac{DynamicMW}{Soln\_Size}$$

Where *j* is for each Subzone; *m* is for the total number of Subzones; Coincident Peak is for the total peak Load for each Subzone; DynamicMW is for the megawatt portion of the solution necessary to resolve the dynamic stability issue(s) for the applicable project; and Soln_Size represents the total compensatory MW addressed by the applicable project.

#### 31.5.3.2.6 Short Circuit Issues

If, after the completion of the prior reliability cost allocation steps, there remains a short circuit issue, the short circuit issue will be deemed a local issue and related costs will not be allocated under this process.

### 31.5.4 Regulated Economic Projects

#### 31.5.4.1 The Scope of Section 31.5.4

As discussed in Section 31.5.1 of this Attachment Y, the cost allocation principles and methodologies of this Section 31.5.4 apply only to regulated economic transmission projects ("RETPs) proposed in response to congestion identified in the CARIS.

This Section 31.5.4 does not apply to generation or demand side management projects, nor does it apply to any market-based projects. This Section 31.5.4 does not apply to regulated backstop solutions triggered by the ISO pursuant to the CSPP, provided, however, the cost allocation principles and methodologies in this Section 31.5.4 will apply to regulated backstop solutions when the implementation of the regulated backstop solution is accelerated solely to reduce congestion in earlier years of the Study Period. The ISO will work with the ESPWG to develop procedures to deal with the acceleration of regulated backstop solutions for economic reasons.

Nothing in this Attachment Y mandates the implementation of any project in response to the congestion identified in the CARIS.

**31.5.4.2 Cost Allocation Principles**

The ISO shall implement the specific cost allocation methodology in Section 31.5.4.4 of this Attachment Y in accordance with the Order No. 1000 Regional Cost Allocation Principles as set forth in Section 31.5.2.1. The specific cost allocation methodology in Section 31.5.4.4 incorporates the following elements:

31.5.4.2.1 The focus of the cost allocation methodology shall be on responses to specific conditions identified in the CARIS.

31.5.4.2.2 Potential impacts unrelated to addressing the identified congestion shall not be considered for the purpose of cost allocation for RETPs.

31.5.4.2.3 Projects analyzed hereunder as proposed RETPs may proceed on a market basis with willing buyers and sellers at any time.

31.5.4.2.4 Cost allocation shall be based upon a beneficiaries pay approach. Cost allocation under the ISO tariff for a RETP shall be applicable only when a super majority of the beneficiaries of the project, as defined in Section 31.5.4.6 of this Attachment Y, vote to support the project.

31.5.4.2.5 Beneficiaries of a RETP shall be those entities economically benefiting from the proposed project. The cost allocation among beneficiaries shall be based upon their relative economic benefit.

31.5.4.2.6 Consideration shall be given to the proposed project's payback period.

31.5.4.2.7 The cost allocation methodology shall address the possibility of cost overruns.

31.5.4.2.8 Consideration shall be given to the use of a materiality threshold for cost allocation purposes.

31.5.4.2.9 The methodology shall provide for ease of implementation and administration to minimize debate and delays to the extent possible.

31.5.4.2.10 Consideration should be given to the "free rider" issue as appropriate. The methodology shall be fair and equitable.

31.5.4.2.11 The methodology shall provide cost recovery certainty to investors to the extent possible.

31.5.4.2.12 Benefits determination shall consider various perspectives, based upon the agreed-upon metrics for analyzing congestion.

31.5.4.2.13 Benefits determination shall account for future uncertainties as appropriate (e.g., load forecasts, fuel prices, environmental regulations).

31.5.4.2.14 Benefits determination shall consider non-quantifiable benefits as appropriate (*e.g.,* system operation, environmental effects, renewable integration).

### 31.5.4.3 Project Eligibility for Cost Allocation

The methodologies in this Section 31.5.4.3 will be used to determine the eligibility of a proposed RETP to have its cost allocated and recovered pursuant to the provisions of this Attachment Y.

31.5.4.3.1 The ISO will evaluate the benefits against the costs (as provided by the Developer) of each proposed RETP over a ten-year period commencing with the proposed commercial operation date for the project. The Developer of each project will pay the cost incurred by the ISO to conduct the ten-year benefit/cost analysis of its project. The ISO, in conjunction with the ESPWG, will develop

methodologies for extending the most recently completed CARIS database as necessary to evaluate the benefits and costs of each proposed RETP.

31.5.4.3.2 The benefit metric for eligibility under the ISO's benefit/cost analysis will be expressed as the present value of the annual NYCA-wide production cost savings that would result from the implementation of the proposed project, measured for the first ten years from the proposed commercial operation date for the project.

31.5.4.3.3 The cost for the ISO's benefit/cost analysis will be supplied by the Developer of the project, and the cost metric for eligibility will be expressed as the present value of the first ten years of annual total revenue requirements for the project, reasonably allocated over the first ten years from the proposed commercial operation date for the project.

31.5.4.3.4 For informational purposes only, the ISO will also calculate the present value of the annual total revenue requirement for the project over a 30 year period commencing with the proposed commercial operation date of the project.

31.5.4.3.5 To be eligible for cost allocation and recovery under this Attachment Y, the benefit of the proposed project must exceed its cost measured over the first ten years from the proposed commercial operation date for the project, and the requirements of section 31.5.4.2 must be met. The total capital cost of the project must exceed $25 million. In addition, a super-majority of the beneficiaries must vote in favor of the project, as specified in Section 31.5.4.6 of this Attachment Y.

31.5.4.3.6 In addition to calculating the benefit metric as defined in Section 31.5.4.3.2, the ISO will calculate additional metrics to estimate the potential

benefits of the proposed project, for information purposes only, in accordance with Section 31.3.1.3.5, for the applicable metric. These additional metrics shall include those that measure reductions in LBMP load costs, changes to generator payments, ICAP costs, Ancillary Service costs, emissions costs, and losses. TCC revenues will be determined in accordance with Section 31.5.4.4.2.3. The ISO will provide information on these additional metrics to the maximum extent practicable considering its overall resource commitments.

31.5.4.3.7 In addition to the benefit/cost analysis performed by the ISO under this Section 31.5.4.3, the ISO will work with the ESPWG to consider the development and implementation of scenario analyses, for information only, that shed additional light on the benefit/cost analysis of a proposed project. These additional scenario analyses may cover fuel and load forecast uncertainty, emissions data and the cost of allowances, pending environmental or other regulations, and alternate resource and energy efficiency scenarios. Consideration of these additional scenarios will take into account the resource commitments of the ISO.

### 31.5.4.4 Cost Allocation for Eligible Projects

As noted in Section 31.5.4.2 of this Attachment Y, the cost of a RETP will be allocated to those entities that would economically benefit from implementation of the proposed project. This methodology shall apply to cost allocation for a RETP, including the ISO's share of the costs of an Interregional Transmission Project proposed as a RETP allocated in accordance with Section 31.5.7 of this Attachment Y.

31.5.4.4.1 The ISO will identify the beneficiaries of the proposed project over a ten-year time period commencing with the proposed commercial operation date for the project. The ISO, in conjunction with the ESPWG, will develop methodologies for extending the most recently completed CARIS database as necessary for this purpose.

31.5.4.4.2 The ISO will identify beneficiaries of a proposed project as follows:

31.5.4.4.2.1 The ISO will measure the present value of the annual zonal LBMP load savings for all Load Zones which would have a load savings, net of reductions in TCC revenues, and net of reductions from bilateral contracts (based on available information provided by Load Serving Entities to the ISO as set forth in subsection 31.5.4.4.2.5 below) as a result of the implementation of the proposed project. For purposes of this calculation, the present value of the load savings will be equal to the sum of the present value of the Load Zone's load savings for each year over the ten-year period commencing with the project's commercial operation date. The load savings for a Load Zone will be equal to the difference between the zonal LBMP load cost without the project and the LBMP load cost with the project, net of reductions in TCC revenues and net of reductions from bilateral contracts.

31.5.4.4.2.2 The beneficiaries will be those Load Zones that experience net benefits measured over the first ten years from the proposed commercial operation date for the project. If the sum of the zonal benefits for those Load Zones with load savings is greater than the revenue requirements for the project (both load savings and revenue requirements measured in present value over the first ten years from

the commercial operation date of the project), the ISO will proceed with the development of the zonal cost allocation information to inform the beneficiary voting process.

31.5.4.4.2.3 Reductions in TCC revenues will reflect the forecasted impact of the project on TCC auction revenues and day-ahead residual congestion rents allocated to load in each zone, not including the congestion rents that accrue to any Incremental TCCs that may be made feasible as a result of this project. This impact will include forecasts of: (1) the total impact of that project on the Transmission Service Charge offset applicable to loads in each zone (which may vary for loads in a given zone that are in different Transmission Districts); (2) the total impact of that project on the NYPA Transmission Adjustment Charge offset applicable to loads in that zone; and (3) the total impact of that project on payments made to LSEs serving load in that zone that hold Grandfathered Rights or Grandfathered TCCs, to the extent that these have not been taken into account in the calculation of item (1) above. These forecasts shall be performed using the procedure described in Appendix B to this Attachment Y.

31.5.4.4.2.4 Estimated TCC revenues from any Incremental TCCs created by a proposed RETP over the ten-year period commencing with the project's commercial operation date will be added to the Net Load Savings used for the cost allocation and beneficiary determination.

31.5.4.4.2.5 The ISO will solicit bilateral contract information from all Load Serving Entities, which will provide the ISO with bilateral energy contract data for modeling contracts that do not receive benefits, in whole or in part, from LBMP

reductions, and for which the time period covered by the contract is within the ten-year period beginning with the commercial operation date of the project. Bilateral contract payment information that is not provided to the ISO will not be included in the calculation of the present value of the annual zonal LBMP savings in section 31.5.4.4.2.1 above.

31.5.4.4.2.5.1 All bilateral contract information submitted to the ISO must identify the source of the contract information, including citations to any public documents including but not limited to annual reports or regulatory filings

31.5.4.4.2.5.2 All non-public bilateral contract information will be protected in accordance with the ISO's Code of Conduct, as set forth in Section 12.4 of Attachment F of the ISO OATT, and Section 6 of the ISO Services Tariff.

31.5.4.4.2.5.3 All bilateral contract information and information on LSE-owned generation submitted to the ISO must include the following information:

(1) Contract quantities on an annual basis:

(a) For non-generator specific contracts, the Energy (in MWh) contracted to serve each Zone for each year.

(b) For generator specific contracts or LSE-owned generation, the name of the generator(s) and the MW or percentage output contracted or self-owned for use by Load in each Zone for each year.

(2) For all Load Serving Entities serving Load in more than one Load Zone, the quantity (in MWh or percentage) of bilateral contract Energy to be applied to each Zone, by year over the term of the contract.

(3) Start and end dates of the contract.

(4) Terms in sufficient detail to determine that either pricing is not indexed to LBMP, or, if pricing is indexed to LBMP, the manner in which prices are connected to LBMP.

(5) Identify any changes in the pricing methodology on an annual basis over the term of the contract.

31.5.4.4.2.5.4 Bilateral contract and LSE-owned generation information will be used to calculate the adjusted LBMP savings for each Load Zone as follows:

$AdjLBMPS_{y,z}$, the adjusted LBMP savings for each Load Zone *z* in each year *y*, shall be calculated using the following equation:

$$AdjLBMPS_{y,z} = \max\left[0, TL_{\mathrm{y,z}} - \sum_{b \in B_{y,z}} \left(BCL_{\mathrm{b,y,z}} * \left(1 - Ind_{\mathrm{b,y,z}}\right)\right) - SG_{\mathrm{y,z}}\right] * \left(LBMP1_{\mathrm{y,z}} - LBMP2_{\mathrm{y,z}}\right)$$

Where:

$TL_{y,z}$ is the total annual amount of Energy forecasted to be consumed by Load in year *y* in Load Zone *z*;

$B_{y,z}$ is the set of blocks of Energy to serve Load in Load Zone *z* in year *y* that are sold under bilateral contracts for which information has been provided to the ISO that meets the requirements set forth elsewhere in this Section 31.5.4.4.2.5

$BCL_{b,y,z}$ is the total annual amount of Energy sold into Load Zone *z* in year *y* under bilateral contract block *b*;

$Ind_{b,y,z}$ is the ratio of (1) the increase in the amount paid by the purchaser of Energy, under bilateral contract block *b*, as a result of an increase in the LBMP in Load Zone *z* in year *y* to (2) the increase in the amount that a purchaser of that amount of Energy would pay if the purchaser paid the LBMP for that Load Zone in that year for all of that Energy (this ratio shall be

zero for any bilateral contract block of Energy that is sold at a fixed price or for which the cost of Energy purchased under that contract otherwise insensitive to the LBMP in Load Zone *z* in year *y*);

$SG_{y,z}$ is the total annual amount of Energy in Load Zone *z* that is forecasted to be served by LSE-owned generation in that Zone in year *y*;

*LBMP1y,z is the* forecasted *annual load-weighted average LBMP* for Load Zone *z* in year *y*, calculated under the assumption that the project is not in place; and

$LBMP2_{y,z}$ is the forecasted annual load-weighted average LBMP for Load Zone *z* in year *y*, calculated under the assumption that the project is in place.

31.5.4.4.2.6 $NZS_z$, the Net Zonal Savings for each Load Zone *z* resulting from a given project, shall be calculated using the following equation:

$$NZS_z = \max\left[0, \sum_{y=PS}^{PS+9}\left(\left(AdjLBMPS_{y,z} - TCCRevImpact_{y,z}\right) * DF_y\right)\right]$$

Where:

*PS* is the year in which the project is expected to enter commercial operation;

$AdjLBMPS_{y,z}$ is as calculated in Section 31.5.4.4.2.5;

$TCCRevImpact_{y,z}$ is the forecasted impact of TCC revenues allocated to Load Zone *z* in year *y*, calculated using the procedure described in Appendix B in Section 31.7 of this Attachment Y; and

$DF_y$ is the discount factor applied to cash flows in year *y* to determine the present value of that cash flow in year *PS*.

31.5.4.4.3 Load Zones not benefiting from a proposed RETP will not be allocated any of the costs of the project under this Attachment Y. There will be no "make whole" payments to non-beneficiaries.

31.5.4.4.4 Costs of a project will be allocated to beneficiaries as follows:

31.5.4.4.4.1 The ISO will allocate the cost of the RETP based on the zonal share of total savings to the Load Zones determined pursuant to Section 31.5.4.4.2 to be beneficiaries of the proposed project. Total savings will be equal to the sum of load savings for each Load Zone that experiences net benefits pursuant to Section 31.5.4.4.2. A Load Zone's cost allocation will be equal to the present value of the following calculation:

$$\text{Zonal Cost Allocation} = \text{Project Cost} * \left(\frac{(\text{Zonal Benefits})}{\text{Total Zonal Benefits for zone with positive net benefits}}\right)$$

31.5.4.4.4.2 Zonal cost allocation calculations for a RETP will be performed prior to the commencement of the ten-year period that begins with the project's commercial operation date, and will not be adjusted during that ten-year period.

31.5.4.4.4.3 Within zones, costs will be allocated to LSEs based on MWhs calculated for each LSE for each zone using data from the most recent available 12 month period. Allocations to an LSE will be calculated in accordance with the following formula:

$$\text{LSE Intrazonal Cost Allocation} = \text{Zonal Cost Allocation} * \left(\frac{\text{LSE Zonal MWh}}{\text{Total Zonal MWh}}\right)$$

31.5.4.4.5 Project costs allocated under this Section 31.5.4.4 will be determined as follows:

31.5.4.4.5.1 The project cost allocated under this Section 31.5.4.4 will be based on the total project revenue requirement, as supplied by the Developer of the project, for the first ten years of project operation. The total project revenue requirement will be determined in accordance with the formula rate on file at the Commission. If there is no formula rate on file at the Commission, then the Developer shall provide to the ISO the project-specific parameters to be used to calculate the total project revenue requirement.

31.5.4.4.5.2 Once the benefit/cost analysis is completed the amortization period and the other parameters used to determine the costs that will be recovered for the project should not be changed, unless so ordered by the Commission or a court of applicable jurisdiction, for cost recovery purposes to maintain the continued validity of the benefit/cost analysis.

31.5.4.4.5.3 The ISO, in conjunction with the ESPWG, will develop procedures to allocate the risk of project cost increases that occur after the ISO completes its benefit/cost analysis under this Attachment Y. These procedures may include consideration of an additional review and vote prior to the start of construction and whether the developer should bear all or part of the cost of any overruns**.**

31.5.4.4.6 The Commission must approve the cost of a proposed RETP for that cost to be recovered through the ISO OATT. The developer's filing with the Commission must be consistent with the project proposal evaluated by the ISO under this Attachment Y in order to be cost allocated to beneficiaries.

### 31.5.4.5 Collaborative Governance Process and Board Action

31.5.4.5.1 The ISO shall submit the results of its project benefit/cost analysis and beneficiary determination to the ESPWG and TPAS, and to the identified beneficiaries of the proposed RETP for comment. The ISO shall make available to any interested party sufficient information to replicate the results of the benefit/cost analysis and beneficiary determination. The information made available will be electronically masked and made available pursuant to a process that the ISO reasonably determines is necessary to prevent the disclosure of any Confidential Information or Critical Energy Infrastructure Information contained in the information made available. Following completion of the review by the ESPWG and TPAS of the project benefit/cost analysis, the ISO's analysis reflecting any revisions resulting from the TPAS and ESPWG review shall be forwarded to the Business Issues Committee and Management Committee for discussion and action.

31.5.4.5.2 Following the Management Committee vote, the ISO's project benefit/cost analysis and beneficiary determination will be forwarded, with the input of the Business Issues Committee and Management Committee, to the ISO Board for review and action. In addition, the ISO's determination of the beneficiaries' voting shares will be forwarded to the ISO Board for review and action. The Board may approve the analysis and beneficiary determinations as submitted or propose modifications on its own motion. If any changes to the benefit/cost analysis or the beneficiary determinations are proposed by the Board, the revised analysis and beneficiary determinations shall be returned to the Management Committee for comment. If the Board proposes any changes to the ISO's voting

share determinations, the Board shall so inform the LSE or LSEs impacted by the proposed change and shall allow such an LSE or LSEs an opportunity to comment on the proposed change. The Board shall not make a final determination on the project benefit/cost analysis and beneficiary determination until it has reviewed the Management Committee comments. Upon final approval of the Board, project benefit/cost analysis and beneficiary determinations shall be posted by the ISO on its website and shall form the basis of the beneficiary voting described in Section 31.5.4.6 of this Attachment Y.

**31.5.4.6 Voting by Project Beneficiaries**

31.5.4.6.1 Only LSEs serving Load located in a beneficiary zone determined in accordance with the procedures in Section 31.5.4.4 of this Attachment Y shall be eligible to vote on a proposed project. The ISO will, in conjunction with the ESPWG, develop procedures to determine the specific list of voting entities for each proposed project.

31.5.4.6.2 The voting share of each LSE shall be weighted in accordance with its share of the total project benefits, as allocated by Section 31.5.4.4 of this Attachment Y.

31.5.4.6.3 The costs of a RETP shall be allocated under this Attachment Y if eighty percent (80%) or more of the actual votes cast on a weighted basis are cast in favor of implementing the project.

31.5.4.6.4 If the proposed RETP meets the required vote in favor of implementing the project, and the project is implemented, all beneficiaries, including those voting “no,” will pay their proportional share of the cost of the project.

31.5.4.6.5 The ISO will tally the results of the vote in accordance with procedures set forth in the ISO Procedures, and report the results to stakeholders. Beneficiaries voting against approval of a project must submit to the ISO their rationale for their vote within 30 days of the date that the vote is taken. Beneficiaries must provide a detailed explanation of the substantive reasons underlying the decision, including, where appropriate: (1) which additional benefit metrics, either identified in the tariff or otherwise, were used; (2) the actual quantification of such benefit metrics or factors; (3) a quantification and explanation of the net benefit or net cost of the project to the beneficiary; and (4) data supporting the metrics and other factors used. Such explanation may also include uncertainties, and/or alternative scenarios and other qualitative factors considered, including state public policy goals. The ISO will report this information to the Commission in an informational filing to be made within 60 days of the vote. The informational filing will include: (1) a list of the identified beneficiaries; (2) the results of the benefit/cost analysis; and (3) where a project is not approved, whether the developer has provided any formal indication to the ISO as to the future development of the project.

## 31.5.5 Regulated Transmission Solutions to Public Policy Transmission Needs

### 31.5.5.1 The Scope of Section 31.5.5

As discussed in Section 31.5.1 of this Attachment Y, the cost allocation principles and methodologies of this Section 31.5.5 apply only to regulated Public Policy Transmission Projects. This Section 31.5.5 does not apply to Other Public Policy Projects, including generation or demand side management projects, or any market-based projects. This Section

31.5.5 does not apply to regulated reliability solutions implemented pursuant to the reliability planning process, nor does it apply to RETPs proposed in response to congestion identified in the CARIS.

A regulated solution shall only utilize the cost allocation methodology set forth in Section 31.5.3 where it is: (1) a Responsible Transmission Owner's regulated backstop solution, (2) an alternative regulated transmission solution selected by the ISO as the more efficient or cost effective regulated transmission solution to satisfy a Reliability Need, (3) seeking cost recovery where it has been halted or cancelled pursuant to the provisions of Section 31.2.8.2, (4) a transmission project identified pursuant to Section 31.2.11.9 as a Gap Solution to be implemented to address a Reliability Need, or (5) a Generator operating under an RMR Agreement as a Gap Solution to an identified Reliability Need. A regulated economic transmission solution proposed in response to congestion identified in the CARIS, and approved pursuant to Section 31.5.4.6, shall only be eligible to utilize the cost allocation principles and methodologies set forth in Section 31.5.4.

**31.5.5.2 Cost Allocation Principles**

The ISO shall implement the specific cost allocation methodology in Section 31.5.5.4 of this Attachment Y in accordance with the Order No. 1000 Regional Cost Allocation Principles as set forth in Section 31.5.2.1. The specific cost allocation methodology in Section 31.5.5.4 incorporates the following elements:

31.5.5.2.1 The focus of the cost allocation methodology shall be on regulated Public Policy Transmission Projects.

31.5.5.2.2 Projects analyzed hereunder as Public Policy Transmission Projects may proceed on a market basis with willing buyers and sellers at any time.

31.5.5.2.3 Cost allocation shall be based on a beneficiaries pay approach.

31.5.5.2.4 Project benefits will be identified in accordance with Section 31.5.5.4.

31.5.5.2.5 Identification of beneficiaries for cost allocation and cost allocation among those beneficiaries shall be according to the methodology specified in Section 31.5.5.4.

**31.5.5.3 Project Eligibility for Cost Allocation**

The Developer of a Public Policy Transmission Project will be eligible for cost allocation in accordance with the process set forth in Section 31.5.5.4 when its project is selected by the ISO as the more efficient or cost effective regulated Public Policy Transmission Project; *provided, however*, that if the appropriate federal, state, or local agency(ies) rejects the selected project's necessary authorizations, or such authorizations are withdrawn, the costs the Developer is eligible to recover under Section 31.4.12.1 shall be allocated in accordance with Section 31.5.5.4.3, except as otherwise determined by the Commission. The Developer of the selected regulated transmission solution may recover its costs in accordance with Section 31.5.6.

**31.5.5.4 Cost Allocation for Eligible Projects**

As noted in Section 31.5.5.2 of this Attachment Y, the identification of beneficiaries for cost allocation and the cost allocation of a selected Public Policy Transmission Project will be conducted in accordance with the process described in this Section 31.5.5.4. This Section will also apply to the allocation within New York of the ISO's share of the costs of an Interregional Transmission Project proposed as a solution to a Public Policy Transmission Need allocated in accordance with Section 31.5.7 of this Attachment Y. The establishment of a cost allocation methodology and rates for a proposed solution that is undertaken by LIPA or NYPA as an Unregulated Transmitting Utility to a Public Policy Transmission Need as determined in

Sections 31.4.2.1 through 31.4.2.3, as applicable, or an Interregional Transmission Project shall occur pursuant to Section 31.5.5.4.4 through 31.5.5.4.6, as applicable. Nothing herein shall deprive a Transmission Owner or Other Developer of any rights it may have under Section 205 of the Federal Power Act to submit filings proposing any other cost allocation methodology to the Commission or create any Section 205 filing rights for any Transmission Owner, Other Developer, the ISO, or any other entity. The ISO shall apply the cost methodology accepted by the Commission.

31.5.5.4.1 If the Public Policy Requirement that results in the identification by the NYPSC of a Public Policy Transmission Need prescribes the use of a particular cost allocation and recovery methodology, then the ISO shall file that methodology with the Commission within 60 days of the issuance by the NYPSC of its identification of a Public Policy Transmission Need. Nothing herein shall deprive a Transmission Owner or Other Developer of any rights it may have under Section 205 of the Federal Power Act to submit filings proposing any other cost allocation methodology to the Commission or create any Section 205 filing rights for any Transmission Owner, Other Developer, the ISO, or any other entity. If the Developer files a different proposed cost allocation methodology under Section 205 of the Federal Power Act, it shall have the burden of demonstrating that its proposed methodology is compliant with the Order No. 1000 Regional Cost Allocation Principles taking into account the methodology specified in the Public Policy Requirement.

31.5.5.4.2 Subject to the provisions of Section 31.5.5.4.1, the Developer may submit to the NYPSC for its consideration – no later than 30 days after the ISO's

selection of the regulated Public Policy Transmission Project – a proposed cost allocation methodology, which may include a cost allocation based on load ratio share, adjusted to reflect, as applicable, the Public Policy Requirement or Public Policy Transmission Need, the party(ies) responsible for complying with the Public Policy Requirement, and the party(ies) who benefit from the transmission facility.

31.5.5.4.2.1 The NYPSC shall have 150 days to review the Developer's proposed cost allocation methodology and to inform the Developer regarding whether it supports the methodology.

31.5.5.4.2.2. If the NYPSC supports the proposed cost allocation methodology, the Developer shall file that cost allocation methodology with the Commission for its acceptance under Section 205 of the Federal Power Act within 30 days of the NYPSC informing the Developer of its support. The Developer shall have the burden of demonstrating that the proposed cost allocation methodology is compliant with the Order No. 1000 Regional Cost Allocation Principles.

31.5.5.4.2.3 If the NYPSC does not support the proposed cost allocation methodology, then the Developer shall take reasonable steps to respond to the NYPSC's concerns and to develop a mutually agreeable cost allocation methodology over a period of no more than 60 days after the NYPSC informing the Developer that it does not support the methodology.

31.5.5.4.2.4 If a mutually acceptable cost allocation methodology is developed during the timeframe set forth in Section 31.5.5.4.2.3, the Developer shall file it with the Commission for acceptance under Section 205 of the Federal Power Act no later

than 30 days after the conclusion of the 60 day discussion period with the NYPSC. The Developer shall have the burden of demonstrating that the proposed cost allocation methodology is compliant with the Order No. 1000 Regional Cost Allocation Principles.

31.5.5.4.2.5 If no mutually agreeable cost allocation methodology is developed, the Developer shall file its preferred cost allocation methodology with the Commission for acceptance under Section 205 of the Federal Power Act no later than 30 days after the conclusion of the 60 day discussion period with the NYPSC. The Developer shall have the burden of demonstrating that its proposed methodology is compliant with the Order No. 1000 Regional Cost Allocation Principles in consideration of the position of the NYPSC. The filing shall include the methodology supported by NYPSC for the Commission's consideration. If the Developer elects to use the load ratio share cost allocation methodology referenced below in Section 31.5.5.4.3, the Developer shall notify the Commission of its intent to utilize the load ratio share methodology and shall include in its notice the NYPSC supported methodology for the Commission's consideration.

31.5.5.4.3. Unless the Commission has accepted an alternative cost allocation methodology pursuant to this Section, the ISO shall allocate the costs of the Public Policy Transmission Project to all Load Serving Entities in the NYCA using the default cost allocation methodology, based upon a load ratio share methodology.

31.5.5.4.4 The NYISO will make any Section 205 filings related to this Section on behalf of NYPA to the extent requested to do so by NYPA. NYPA shall bear the burden of demonstrating that such a filing is compliant with the Order No. 1000 Regional Cost Allocation Principles. NYPA shall also be solely responsible for making any jurisdictional reservations or arguments related to their status as non-Commission-jurisdictional utilities that are not subject to various provisions of the Federal Power Act.

31.5.5.4.5 The cost allocation methodology and any rates for cost recovery for a proposed solution to a Public Policy Transmission Need undertaken by LIPA, as an Unregulated Transmitting Utility (for purposes of this section a "LIPA project"), shall be established and recovered as follows:

31.5.5.4.5.1 *For costs solely to LIPA customers.* The cost allocation methodology and rates to be established for a LIPA project, for which cost recovery will only occur from LIPA customers, will be established pursuant to Article 5, Title 1-A of the New York Public Authorities Law, Sections 1020-f(u) and 1020-s. Prior to the adoption of any cost allocation mechanism or rates for such a LIPA project, and pursuant to Section 1020-f(u), the Long Island Power Authority's Board of Trustees shall request that the NYDPS provide a recommendation with respect to the cost allocation methodology and rate that LIPA has proposed and the Board of Trustees shall consider such recommendation in accordance with the requirements of Section 1020-f(u). Upon approval of the cost allocation mechanism and/or rates by the Long Island Power Authority's Board of Trustees, LIPA shall provide to the ISO, for purposes of inclusion within the ISO OATT and filing with FERC

on an informational basis only, a description of the cost allocation mechanism and the rate that LIPA will charge and collect within the Long Island Transmission District.

31.5.5.4.5.2 *For Costs for a LIPA Project That May be Allocated to Other Transmission Districts.* A LIPA project that meets a Public Policy Transmission Need as determined by the NYPSC pursuant to Section 31.4.2.3(iii) may be allocated to market participants outside of the Long Island Transmission District. The cost allocation methodology and rate for such a LIPA project shall be established in accordance with the following procedures. LIPA's proposed cost allocation methodology and/or rate shall be reviewed and approved by the Long Island Power Authority's Board of Trustees pursuant to Article 5, Title 1-A of the New York Public Authorities Law, Sections 1020-f(u) and 1020-s. Prior to the adoption of any cost allocation mechanism or rates for such project and pursuant to Section 1020-f(u), the Long Island Power Authority's Board of Trustees shall request that the NYDPS provide a recommendation with respect to the cost allocation methodology and rate that LIPA has proposed and the Board of Trustees shall consider such recommendation in accordance with the requirements of Section 1020-f(u). LIPA shall inform the ISO of the cost allocation methodology and rate that has been approved by the Long Island Power Authority's Board of Trustees for filing with the Commission.

Upon approval by the Long Island Power Authority's Board of Trustees, LIPA shall submit and request that the ISO file the LIPA cost allocation methodology for approval with the Commission. Any cost allocation

methodology for a LIPA project that allocates costs to market participants outside of the Long Island Transmission District shall be reviewed as to whether there is comparability in the derivation of the cost allocation for market participants such that LIPA has demonstrated that the proposed cost allocation is compliant with the Order No. 1000 cost allocation principles, there are benefits provided by the project to market participants outside of the Long Island Transmission District, and that the proposed allocation is roughly commensurate to the identified benefits.

Article 5, Title 1-A of the New York Public Authorities Law, Sections 1020-f(u) and 1020-s, requires that LIPA's rates be established at the lowest level consistent with sound fiscal and operating practices of the Long Island Power Authority and which provide for safe and adequate service. Upon approval of a LIPA rate by the Long Island Power Authority's Board of Trustees pursuant to Section 1020-f(u), LIPA shall submit, and request that the ISO file, the LIPA rate with the Commission for review under the same comparability standard as applied to the review of changes in LIPA's TSC under Attachment H of this tariff.

In the event that the cost allocation methodology or rate approved by the Long Island Power Authority's Board of Trustees did not adopt the NYDPS recommendation, the NYDPS recommendation shall be included in the filing for the Commission's consideration.

31.5.5.4.5.3 *Support for Filing*. LIPA shall intervene in support of the filing(s) made pursuant to Section 31.5.5.4.5 at the Commission and shall take the responsibility to demonstrate that: (i) the cost allocation methodology and/or rate approved by

the Long Island Power Authority's Board of Trustees meets the applicable standard of comparability, and (ii) the Commission should accept such methodology or rate for filing. LIPA shall also be responsible for responding to, and seeking to resolve, concerns about the contents of the filing that might be raised in such proceeding.

31.5.5.4.5.4 *Billing of LIPA Charges Outside of the Long Island Transmission District*. For Transmission Districts other than the Long Island Transmission District, the ISO shall bill for LIPA, as a separate charge, the costs incurred by LIPA for a solution to a Public Policy Transmission Need allocated using the cost allocation methodology and rates established pursuant to Section 31.5.5.4.5.2 and accepted for filing by the Commission and shall remit the revenues collected to LIPA each Billing Period in accordance with the ISO's billing and settlement procedures.

31.5.5.4.6 The inclusion in the ISO OATT or in a filing with the Commission of the cost allocation and charges for recovery of costs incurred by NYPA or LIPA related to a solution to a transmission need driven by a Public Policy Requirement or Interregional Transmission Project as provided for in Sections 31.5.5.4.4 and 31.5.5.4.5 shall not be deemed to modify the treatment of such rates as non-jurisdictional pursuant to Section 201(f) of the FPA.

**31.5.6 Cost Recovery for Regulated Projects**

Responsible Transmission Owners, Transmission Owners and Other Developers will be entitled, if eligible for cost recovery under Section 31.2 of this Attachment Y, to full recovery of all reasonably incurred costs, including a reasonable return on investment and any applicable incentives, related to the development, construction, operation and maintenance of regulated

transmission solutions, including transmission Gap Solutions, proposed or undertaken pursuant to the provisions of this Attachment Y to meet a Reliability Need. If a Market Participant's Generator is operating under an RMR Agreement as a Gap Solution, the Market Participant will be paid in accordance with Rate Schedule 8 of the ISO Services Tariff, and the ISO will recover costs related to RMR Agreements from LSEs in accordance with Schedule 14 of the ISO OATT. Transmission Owners and Other Developers will be entitled to recovery of costs associated with the implementation of a regulated economic transmission project ("RETP") in accordance with the provisions of Section 31.5.6 of this Attachment Y. Developers will be entitled to recover the costs, to the extent permitted under Sections 31.4 and 31.5.6.5 of this Attachment Y, associated with the implementation of a regulated Public Policy Transmission Project in accordance with the requirements in Section 31.5.6.5 of this Attachment Y.

31.5.6.1 The Responsible Transmission Owner, Transmission Owner or Other Developer will receive cost recovery for a regulated transmission solution it undertakes to meet a Reliability Need pursuant to Section 31.2 of this Attachment Y that is subsequently halted in accordance with the criteria established pursuant to Section 31.2.8.2 of this Attachment Y. Such costs will include reasonably incurred costs through the time of cancellation, including any forward commitments made.

31.5.6.2 The Responsible Transmission Owner, Transmission Owner or Other Developer will recover its costs described in this Section 31.5 incurred with respect to the implementation of a regulated transmission solution to Reliability Needs, including a transmission Gap Solution, in accordance with the provisions of Rate Schedule 10 of this ISO OATT, or as determined by the Commission.

Provided further that cost recovery for regulated transmission projects undertaken by a Transmission Owner pursuant to this Attachment Y shall be in accordance with the provisions of the NYISO/TO Reliability Agreement.

31.5.6.3 If a Market Participant's Generator is operating under an RMR Agreement as a Gap Solution, the Market Participant will be paid in accordance with Rate Schedule 8 of the ISO Services Tariff. The ISO will recover costs related to RMR Agreements from LSEs in accordance with Schedule 14 of the ISO OATT. With the exception of a Generator operating under an RMR Agreement as a Gap Solution, costs related to non-transmission regulated solutions to Reliability Needs will be recovered by Responsible Transmission Owners, Transmission Owners and Other Developers in accordance with the provisions of New York Public Service Law, New York Public Authorities Law, or other applicable state law. Except as otherwise provided in the Gap Solution process in Section 31.2.11 of this Attachment Y, a Responsible Transmission Owner, a Transmission Owner, or Other Developer may propose and undertake a regulated non-transmission solution, provided that the appropriate state agency(ies) has established cost recovery procedures comparable to those provided in this tariff for regulated transmission solutions to ensure the full and prompt recovery of all reasonably-incurred costs related to such non-transmission solutions. Nothing in this section shall affect the Commission's jurisdiction over the sale and transmission of electric energy subject to the jurisdiction of the Commission.

31.5.6.4 For a regulated economic transmission project that is approved pursuant to Section 31.5.4.6 of this Attachment Y, the Transmission Owner or Other

Developer shall have the right to make a filing with the Commission, under Section 205 of the Federal Power Act, for approval of its costs associated with implementation of the project. The filing of the Transmission Owner or Other Developer must be consistent with its project proposal made to and evaluated by the ISO under Section 31.5.4 of this Attachment Y. Costs will be recovered when the project is completed pursuant to a rate schedule filed with and accepted by the Commission in accordance with the cost recovery requirements set forth in this Section, or as otherwise determined by the Commission. Upon request by NYPA, the ISO will make a filing on behalf of NYPA.

31.5.6.5 For a regulated Public Policy Transmission Project, the Developer shall have the right to make a filing with the Commission under Section 205 of the Federal Power Act, for approval of its costs eligible for recovery under Section 31.4 and this Section 31.5.6.5.

31.5.6.5.1 The Developer of a Public Policy Transmission Project selected by the ISO as the more efficient or cost-effective Public Policy Transmission Project will be entitled to full recovery of all reasonably incurred costs, including a reasonable return on investment and any applicable incentives, related to the development, construction, operation, and maintenance of the selected Public Policy Transmission Project. Such cost recovery will include reasonable costs incurred by the Developer to provide a more detailed study or cost estimate for such project at the request of the NYPSC, and to prepare the application required to comply with New York Public Service Law Article VII, or any successor statute or any other applicable permits, and to seek other necessary authorizations. The

filing of the Developer must be consistent with its project proposal submitted to, evaluated by and selected by the ISO under Section 31.4 of this Attachment Y. The period for cost recovery, if any cost recovery is approved, will be determined by the Commission and will begin if and when the project is completed, or as otherwise determined by the Commission.

31.5.6.5.2 If the appropriate federal, state or local agency(ies) either rejects a necessary authorization, or approves and later withdraws authorization, for the selected Public Policy Transmission Project, all of the necessary and reasonable costs incurred and commitments made up to the final federal, state or local regulatory decision, including reasonable and necessary expenses incurred to implement an orderly termination of the project, will be recoverable by the Developer. The period for cost recovery will be determined by the Commission and will begin as determined by the Commission.

31.5.6.5.3 Upon request by NYPA, the ISO will make a filing on behalf of NYPA under this Section 31.5.6.5.

31.5.6.6 To the extent that Incremental TCCs are created as a result of a regulated economic transmission project that has been approved for cost recovery under the NYISO Tariff, those Incremental TCCs that can be sold will be auctioned or otherwise sold by the ISO. The ISO shall determine the amount of Incremental TCCs that may be awarded to an expansion in accordance with the provisions of Section 19.2.2 of Attachment M of the ISO OATT. The ISO will use these revenues to offset the revenue requirements for the project. The Incremental TCCs shall continue to be sold for the depreciable life of the project, and the

revenues offset will commence upon the first payment of revenues related to a sale of Incremental TCCs on or after the charge for a specific RETP is implemented.

### 31.5.7 Cost Allocation for Eligible Interregional Transmission Projects

#### 31.5.7.1 Costs of Approved Interregional Transmission Projects

The cost allocation methodology reflected in this Section 31.5.7.1 shall be referred to as the "Northeastern Interregional Cost Allocation Methodology" (or "NICAM"), and shall not be modified without the mutual consent of the Section 205 rights holders in each region.

The costs of Interregional Transmission Projects, as defined in the Interregional Planning Protocol, evaluated under the Interregional Planning Protocol and selected by ISO-NE, PJM and the ISO in their regional transmission plans for purposes of cost allocation under their respective tariffs shall, when applicable, be allocated to the ISO-NE region, PJM region and the ISO region in accordance with the cost allocation principles of FERC Order No. 1000, as follows:

(a) To be eligible for interregional cost allocation, an Interregional Transmission Project must be selected in the regional transmission plan for purposes of cost allocation in each of the transmission planning regions in which the transmission project is proposed to be located, pursuant to agreements and tariffs on file at FERC for each region. With respect to Interregional Transmission Projects and other transmission projects involving the ISO and PJM, the cost allocation of such projects shall be in accordance with the Joint Operating Agreement ("JOA") among and between the ISO and PJM. With respect to Interregional Transmission Projects and other transmission projects involving the ISO and ISO-NE, the cost allocation for such projects shall be in accordance with this Section 31.5.7 of Attachment Y of the NYISO Open Access Transmission Tariff and with the respective tariffs of ISO-NE.

(b) The share of the costs of an Interregional Transmission Project allocated to a region will be determined by the ratio of the present value of the estimated costs of such region's displaced regional transmission project to the total of the present values of the estimated costs of the displaced regional transmission projects in all regions that have selected the Interregional Transmission Project in their regional transmission plans.

(i) The present values of the estimated costs of each region's displaced regional transmission project shall be based on a common base date that will be the beginning of the calendar month of the cost allocation analysis for the subject Interregional Transmission Project (the "Base Date").

(ii) In order to perform the analysis in this Section 31.5.7.1(b), the estimated cost of the displaced regional transmission projects shall specify the year's dollars in which those estimates are provided.

(iii) The present value analysis for all displaced regional transmission projects shall use a common discount rate. The regions having displaced projects will mutually agree, in consultation with their respective transmission owners, and for purposes of the ISO, its other stakeholders, on the discount rate to be used for the present value analysis.

(iv) For the purpose of this allocation, cost estimates shall use comparable cost estimating procedures. In the Interregional Planning Stakeholder Advisory Committee review process, the regions having displaced projects will review and determine, in consultation with their respective transmission owners, and for purposes of the NYISO, its other stakeholders, that reasonably comparable estimating procedures have been used prior to applying this cost allocation.

(c) No cost shall be allocated to a region that has not selected the Interregional Transmission Project in its regional transmission plan.

(d) When a portion of an Interregional Transmission Project evaluated under the Interregional Planning Protocol is included by a region (Region 1) in its regional transmission plan but there is no regional need or displaced regional transmission project in Region 1, and the neighboring region (Region 2) has a regional need or displaced regional project for the Interregional Transmission Project and selects the Interregional Transmission Project in its regional transmission plan, all of the costs of the Interregional Transmission Project shall be allocated to Region 2 in accordance with the NICAM and none of the costs shall be allocated to Region 1. However, Region 1 may voluntarily agree, with the mutual consent of the Section 205 rights holders in the other affected region(s) (including the Long Island Power Authority and the New York Power Authority in the NYISO region) to use an alternative cost allocation method filed with and accepted by the Commission.

(e) The portion of the costs allocated to a region pursuant to the NICAM shall be further allocated to that region's transmission customers pursuant to the applicable provisions of the region's FERC-filed documents and agreements, for the ISO in accordance with Section 31.5.1.7 of Attachment Y of the ISO OATT.

(f) The following example illustrates the cost allocation for such an Interregional Transmission Project:

- A cost allocation analysis of the costs of Interregional Transmission Project Z is to be performed during a given month establishing the beginning of that month as the Base Date.

- Region A has identified a reliability need in its region and has selected a transmission project (Project X) as the preferred solution in its regional plan. The estimated cost of Project X is: Cost (X), provided in a given year's dollars. The number of years from the Base Date to the year associated with the cost estimate of Project (X) is: N(X).
- Region B has identified a reliability need in its region and has selected a transmission project (Project Y) as the preferred solution in its Regional Plan. The estimated cost of Project Y is: Cost (Y), provided in a given year's dollars. The number of years from the Base Date to the year associated with the cost estimate of Project (Y) is: N(Y).
- Regions A and B, through the interregional planning process have determined that an Interregional Transmission Project (Project Z) will address the reliability needs in both regions more efficiently and cost-effectively than the separate regional projects. The estimated cost of Project Z is: Cost (Z). Regions A and B have each determined that Interregional Transmission Project Z is the preferred solution to their reliability needs and have adopted that Interregional Transmission Project in their respective regional plans in lieu of Projects X and Y respectively. If Regions A and B have agreed to bear the costs of upgrades in other affected transmission planning regions, these costs will be considered part of Cost (Z).
- The discount rate used for all displaced regional transmission projects is: D
- Based on the foregoing assumptions, the following formulas will be used:
    - Present Value of Cost (X) = PV Cost (X) = Cost (X) / $(1+D)^{N(X)}$
    - Present Value of Cost (Y) = PV Cost (Y) = Cost (Y) / $(1+D)^{N(Y)}$

- Cost Allocation to Region A = Cost (Z) x PV Cost (X)/[PV Cost (X) + PV Cost (Y)]
- Cost Allocation to Region B = Cost (Z) x PV Cost (Y)/[PV Cost (X) + PV Cost (Y)]

- Applying those formulas, if:

  Cost (X) = $60 Million and N(X) = 8.25 years

  Cost (Y) = $40 Million and N(Y) = 4.50 years

  Cost (Z) = $80 Million

  D = 7.5% per year

  Then:

  PV Cost (X) = $60/(1+0.075)^{8.25}$ = 33.039 Million

  PV Cost (Y) = $40/(1+0.075)^{4.50}$ = 28.888 Million

  Cost Allocation to Region A = $80 x 33.039/(33.039 + 28.888) = $42,681 Million

  Cost Allocation to Region B = $80 x 28.888/(33.039+28.888) = $37.319 Million

**31.5.7.2 Other Cost Allocation Arrangements**

(a) Except as provided in Section 31.5.7.2(b), the NICAM is the exclusive means by which any costs of an Interregional Transmission Project may be allocated between or among PJM, the ISO, and ISO-NE.

(b) Nothing in the FERC-filed documents of ISO-NE, the ISO or PJM shall preclude agreement by entities with cost allocation rights under Section 205 of the Federal Power Act for their respective regions (including the Long Island Power Authority and the New York Power Authority in the ISO region) to enter into separate agreements to allocate the cost-of Interregional Transmission Projects proposed to be located in their regions as an alternative to

the NICAM, or other transmission projects identified pursuant to assessments and studies conducted pursuant to Section 6 of the Interregional Planning Protocol. Such other cost-allocation methodologies must be approved in each region pursuant to the Commission-approved rules in each region, filed with and accepted by the Commission, and shall apply only to the region's share of the costs of an Interregional Transmission Project or other transmission projects pursuant to Section 6 of the Interregional Planning Protocol, as applicable.

#### 31.5.7.3 Filing Rights

Nothing in this Section 31.5.7 will convey, expand, limit or otherwise alter any rights of ISO-NE, the ISO, PJM, each region's transmission owners, market participants, or other entities to submit filings under Section 205 of the Federal Power Act regarding interregional cost allocation or any other matter.

Where applicable, the regions have been authorized by entities that have cost allocation rights for their respective regions to implement the provisions of this Section 31.5.7.

#### 31.5.7.4. Merchant Transmission and Individual Transmission Owner Projects

Nothing in this Section 31.5.7 shall preclude the development of Interregional Transmission Projects that are funded solely by merchant transmission developers or by individual transmission owners.

#### 31.5.7.5 Consequences to Other Regions from Regional or Interregional Transmission Projects

Except as provided herein in Sections 31.5.7.1 and 31.5.7.2, or where cost responsibility is expressly assumed by ISO-NE, the ISO or PJM in other documents, agreements or tariffs on file with FERC, neither the ISO-NE region, the ISO region nor the PJM region shall be responsible for compensating another region or each other for required upgrades or for any other

consequences in another planning region associated with regional or interregional transmission facilities, including but not limited to, transmission projects identified pursuant to Section 6 of the Interregional Planning Protocol and Interregional Transmission Projects identified pursuant to Section 7 of the Interregional Planning Protocol.

## 31.8 Appendix E – Generator Deactivation Notice Form

### 31.8.1 Instructions

31.8.1.1 Before a Generator may be Retired or enter into a Mothball Outage, the Market Participant must satisfy the requirements set forth in Section 31.2.11 of Attachment Y to the OATT, including submitting to the NYISO a completed Generator Deactivation Notice using the form set forth in this Appendix E of Attachment Y to the OATT, and providing the information required by Appendix F of Attachment Y to the OATT.

31.8.1.2 In accordance with the requirements set forth in Section 31.2.11.2.1 of Attachment Y to the OATT and ISO Procedures, the Market Participant shall submit to the NYISO via electronic mail (a) the Generator Deactivation Notice form to generator_retirement@nyiso.com and (b) all information required by Appendix F of Attachment Y to NYISO Stakeholder Services, to the attention of the Director of Market Mitigation and Analysis.

31.8.1.3 The NYISO will review the information received pursuant to Section 31.2.11.2.2 of the OATT to determine whether it is complete. The NYISO will notify the Market Participant to provide any additional information that is required in order for the Generator Deactivation Notice to be determined to be complete.

31.8.1.4 The twelve-month notice period applicable to a Generator(s) proposing to be Retired or enter into a Mothball Outage will begin to run on the date that the NYISO issues a written notice to the Market Participant indicating that the Generator Deactivation Notice (including the information received and supporting certification) are complete.

31.8.1.5 The Market Participant has a continuing obligation to timely submit additional information pursuant to Section 31.9.4 of Appendix F, under Attachment Y to the NYISO OATT, and as otherwise required under the ISO Tariffs. All such information shall be sent to NYISO Stakeholder Services, to the attention of the Director of Market Mitigation and Analysis.

### 31.8.2 Submitting Entity's Information

31.8.2.1 Name of entity submitting notice:

_____ ("submitting entity")

31.8.2.2 Submitting entity's interest in and relationship with Generator(s) (check all that apply):

[ ] Owner (and if part owner, percent) of Generator(s)
[ ] Operator of Generator(s)

[ ] Market Participant
[ ] Other _____

If the submitting entity is not both the owner and operator, provide the following information for (a) the owner, (b) the operator, (c) Market Participant, and (d) the submitting entity:

31.8.2.3 State of organization or incorporation:

_____

31.8.2.4 Contact information

Name of contact person and alternate contact person, title, relationship to the submitting entity, mailing address, e-mail address, office phone number, and cell phone number:

**31.8.3 Identity of Generator(s) Subject to Generator Deactivation Notice**

Location:

Unit Name:_____ PTID _____ Nameplate Capacity in MW: _____

Unit Name:_____ PTID _____ Nameplate Capacity in MW: _____

Unit Name:_____ PTID _____ Nameplate Capacity in MW: _____

Unit Name:_____ PTID _____ Nameplate Capacity in MW: _____

Revenue Meter Location(s) (Use PTIDs):

**31.8.4 Proposed Generator Deactivation**

31.8.4.1 The Generator Deactivation Notice is for the Generator(s) (check one):

[ ] to be Retired
[ ] to enter into a Mothball Outage.

31.8.4.2 If the submitting entity is proposing to enter into a Mothball Outage, please check the box below to acknowledge that the Generator(s) is able to return to service within 180 days.

[ ] Generator(s) is able to return to service within 180 days

Please note: If the submitting entity believes that there is good cause for why a Generator will not be able to return to service within 180 days, the submitting entity must separately provide for each such Generator the proposed

number of days for return and supporting information to the NYISO for review. The NYISO will determine whether the information provided satisfies the requirements of Section 5.18.3.2 of the ISO Services Tariff. If the Generator Deactivation Notice is for more than one Generator, and the response to this subsection 31.8.4.2 is not the same for all Generators, specify by Unit Name and PTID which Generators are able and which are not able to return to service within 180 days.

31.8.4.3 If the submitting entity is proposing for the Generator(s) to be Retired greater than 365 days after the Generator Deactivation Assessment Start Date (as that term is defined in Section 31.1.1 of Attachment Y to the NYISO OATT,) the desired retirement date is: [day] of [month] of [year].

31.8.4.4 If the Generator Deactivation Notice is proposing for the Generator(s) to enter into a Mothball Outage greater than 365 days after the Generator Deactivation Assessment Start Date, the desired date to enter into a Mothball Outage is: [day] of [month] of [year]. The submitting entity proposes to resume operation and participation in the ISO Administered Markets on: [day] of [month] of [year].

31.8.4.5 The submitting entity is interested in its Generator(s) being Retired or entering into a Mothball Outage in fewer than 365 days if the requirements for early deactivation are satisfied under the Gap Solution process in Section 31.2.11:

[ ] Yes
[ ] No

**31.8.5 Acknowledgments**

By submitting the Generator Deactivation Notice, the submitting entity acknowledges:

- After the NYISO determines that the Generator Deactivation Notice is complete, the NYISO will post a notice of that determination (and will notify the submitting entity.)

- If the submitting entity rescinds this Generator Deactivation Notice after the NYISO determines it to be complete, the submitting entity must reimburse the NYISO and the relevant New York Transmission Owner(s) in accordance with Section 31.2.11.15 of Attachment Y of the NYISO OATT the actual costs that each incurred in performing their responsibilities under Section 31.2.11 of Attachment Y of the NYISO OATT and Section 23.4.5.6 of the ISO Services Tariff in response to the submitting entity's submission of this Generator Deactivation Notice, including any costs associated with using contractors.

**31.8.6 Submitted By:**

**Certification**

The undersigned certifies that he or she is an officer of the submitting entity, that he or she is authorized to execute this Certification and submit this Generator Deactivation Notice on behalf of the submitting entity, and that the information and statements contained herein (including any and all attachments, and information required by Appendix F of Attachment Y to the NYISO OATT submitted herewith,) and in this certification are true and correct to the best of his or her information, knowledge and belief, having conducted due diligence.

_____

Signature

Name: _____ Title: _____

Date: _____

## 31.9 Appendix F – Gap Solution Process Cost, Revenue, and Other Information Requirements

### 31.9.1 Overview of Information Requirements

This Appendix F governs the information that must be received by the ISO from Market Parties for Initiating Generators, proposed Gap Solutions pursuant to Section 31.2.11.3 of Attachment Y, and Generators identified by the ISO pursuant to Section 31.2.11.4 of Attachment Y. The term "information" as used in this Appendix F, and in Section 31.2 of Attachment Y regarding it, includes all sources and types of information and data. The information required by this Appendix shall be separately stated from and is in addition to the information requirements for Generators in certain outages set forth in Section 5.18 of the ISO Services Tariff, the information required by the ISO pursuant to Section 23.4.5.6 of the ISO Services Tariff, and the Gap Solution process project information requirements set forth in Section 31.2.11.3 of this Attachment Y. If the information required by this Appendix does not exist on the date due to the ISO, the Market Party shall promptly provide it to the ISO if and when it does exist in whole or in part.

### 31.9.2 Information Requirements Applicable to Initiating Generators

31.9.2.1 The Market Party for an Initiating Generator must submit the information specified below, and any other information specified by the ISO on the section of its website identified for RMR Information Requirements, in the form and manner directed by the ISO. The items and their costs identified for (a) through (d), and (e) in this Section shall include only those costs necessary for the Initiating Generator to operate in accordance with Good Utility Practice for the duration of the relevant information period (as set forth in Section 31.9.8).

(a) Capital expenses, including those necessary to comply with federal or state environmental or safety laws, rules, regulations, and requirements, separately stating the financing cost (*e.g.*, interest and fees) for each item;

(b) Fixed operating and maintenance costs;

(c) Variable operating and maintenance costs, such as fuel, emissions, and start up costs, and other costs identified by the ISO in accordance with ISO Procedures; and if there is any difference between the submitted information and the information in the ISO's Reference Level System at the time of the submission, and an explanation of the reason for the difference.

(d) The quantity of specific items of inventory necessary to be maintained, and costs thereof;

(e) The cost of expenditures other than those identified in (a) through (d) of this section that are necessary for the Generator to operate;

(f) All information pertaining to the capital structure of the Generator and its financing structure, the sources of capital, financing agreements, and dividend payout schedules;

(g) If the Generator Deactivation Notice is for the Generator to be Retired, (a) all existing agreements and proposals pertaining to the cost of opportunities that would be foregone if the Generator is not retired, such agreements being for the reuse, repurposing, or distribution of the real property of or on which the unit is located, its personal property or appurtenances; and (b) all agreements that contain a cost, premium, or fee for termination of all or a portion thereof;

(h) If the Generator is in an ICAP Ineligible Forced Outage or is Mothballed, and the Generator Deactivation Notice is for a retirement prior to the expiration of the period set forth in Section 5.18.[*] of the Services Tariff, the costs that are necessary to enable the Generator to return to service; and

(i) All sources of revenue, and the amount of, and terms and conditions associated with each source of revenues related to the construction of, investment in, upgrade to, or operation of the Generator.

31.9.2.2 For each item of cost or revenue, the Market Party shall specify whether it can be avoided, in whole or in part or diminished, if the Generator (a) ceases operations in the manner specified in its Generator Deactivation Notice, or (b) does not resume service from an ICAP Ineligible Forced Outage or Mothball Outage state. For each cost that can

be avoided, the Market Party shall specify how it plans to do so and the potentially viable options examined to minimize the cost.

### 31.9.3 Information Requirements Applicable to Proposed Gap Solutions and Generators Identified Pursuant to Section 31.2.11.4

31.9.3.1 The Market Party for a proposed Gap Solution or a Generator identified pursuant to Section 31.2.11.4 shall submit the information identified below, and any other information specified by the ISO on the ISO's website, in the form and manner directed by the ISO.

31.9.3.2 If the NYISO identifies a Generator pursuant to Section 31.2.11.4 of Attachment Y, the Market Party shall submit the information set forth in Section 31.9.2.1 and 31.9.2.2.

31.9.3.3 If a proposed Gap Solution is a new Generator, the Market Party shall submit those costs necessary for the Generator to be sited, permitted, and constructed, and the information below. The items and their costs identified for (a) through (d) in this Section shall include only those costs necessary for the Generator to operate in accordance with Good Utility Practice for the duration of the relevant information period.

(a) Capital expenses, including those necessary to comply with federal or state environmental or safety laws, rules, regulations, and requirements, separately stating the financing cost (*e.g.*, interest and fees) for each item;

(b) Fixed operating and maintenance costs;

(c) Variable operating and maintenance costs;

(d) The quantity of specific items of inventory necessary to be maintained, and costs thereof;

(e) All information pertaining to the capital structure of the Generator and its financing structure, including the sources of capital, financing agreements, and dividend payout schedules;

(f) All existing agreements and proposals pertaining to opportunity costs that would be foregone if the Generator served as a Gap Solution; and

(g) All sources of revenue, and the amount of, and terms and conditions associated with each source of revenues related to the construction of, investment in, upgrade to, or operation of the proposed Gap Solution or Generator.

31.9.3.4 If a proposed Gap Solution is a demand response project, solely to the extent required to provide the demand response service described in the proposal as a Gap Solution, the Market Party shall provide:

(a) Capital expenses, including those necessary to comply with federal or state environmental or safety laws, rules, regulations or requirements which would be required over the current course of business to equip the resource(s), separately stating the financing cost (*e.g.*, interest and fees) for each item;

(b) Fixed operating and maintenance costs, and identifying if the cost also benefits any other aspect of the resource or another entity;

(c) Variable operating and maintenance costs, such as additional fuel, emissions, and start up or ramping costs;

(d) The quantity of specific items of inventory necessary to be maintained, and costs thereof;

(e) The cost of expenditures other than those identified in (a) through (d) of this section that are necessary to provide the demand response service described in the proposal as a Gap Solution;

(f) All information pertaining to the capital structure of the entity that comprises the demand response project and its financing structure, including the sources of capital, financing agreements, and dividend payout schedules; and

(g) All sources of revenue, and the amount of, and terms and conditions associated with each source of revenues related to the development or construction of, investment in, upgrade to, or operation or provision of the service.

31.9.3.5 If a proposed Gap Solution is a transmission project, the Market Party shall provide:

(a) Capital expenses, including those necessary to comply with federal or state environmental or safety requirements, separately stating the financing cost (*e.g.*, interest and fees) for each item;

(b) Fixed operating and maintenance costs;

(c) Variable operating and maintenance costs;

(d) The quantity of specific items of inventory necessary to be maintained, and costs thereof;

(e) The cost of expenditures other than those identified in (a) through (d) of this Section that are necessary to enable the project to operate, including any costs to obtain right of way, siting, and other federal, state and local permits;

(f) All information pertaining to the capital structure of the project and its financing structure, including the sources of capital, financing agreements, and dividend payout schedules;

(g) All existing agreements and proposals pertaining to opportunity costs that would be foregone if the project served as a Gap Solution; and

(h) All sources of revenue, and the amount of, and terms and conditions associated with each source of revenue related to the construction of, investment in, upgrade to, or operation of the project.

**31.9.4 Obligation to Submit Further Information**

Market Parties for Initiating Generators, proposed Gap Solutions, and Generators identified by the ISO pursuant to Section 31.2.11.4, shall provide any new information, and shall update and revise information previously submitted to the ISO in accordance with Sections 31.9.2 or 31.9.3, (i) no more than fifteen days after (a) a material change (or a series of changes that results in a material change) in (I) the physical condition of an Initiating Generator, proposed Gap Solution, or Generator identified by the ISO pursuant to Section 31.2.11.4, or any aspect of its proposal or (II) the information previously submitted, (b) an event occurring that makes any element of the information submitted materially inaccurate, (c) actual cost information becoming available where estimated information had been provided, (d) changes to costs based on physical events or regulatory developments that might reasonably be expected to impact planned operations, and also (ii) promptly upon the request of the ISO for any other information. The obligation to provide information pursuant to this Section 31.9.4 shall cease (a) for any proposed Gap Solution or Generator identified by the ISO pursuant to Section 31.2.11.4 (other than an

Initiating Generator) on the earlier of the date (x) the ISO provides notice that a Gap Solution is not needed, the request for Gap Solutions is withdrawn, or that the ISO determines a Gap Solution other than it is expected to satisfy the Reliability Need, and (b) for any Initiating Generator, upon the earlier of the date that (x) it withdraws its Generator Deactivation Notice if it stated it was a notice of retirement, or (y) it permanently retires.

31.9.5 The Market Party shall provide the ISO the actual costs and revenues for each item in Sections 31.9.2 through 31.9.4 to the greatest extent practicable. If actual costs and revenues are not available, the Market Party shall provide estimated costs and revenues along with a description of how the estimates were prepared. The Market Party must identify and describe the accounting protocols used to identify or determine all actual and estimated costs and revenues.

31.9.6 For each cost identified under Subsections (a), (b), (d) and (e) of Sections 31.9.2.1, 31.9.3.1, 31.9.3.4, or 31.9.3.5, or Subsections (a), (b) and (d) of Section 31.9.3.3, the Market Party shall provide a detailed plan specifying the schedule and timing of the planned action and expenditure, and if it is an existing Resource, an explanation and supporting documentation of how that plan compares to the Market Party's past similar expenditures, actions, and protocols. The Market Party shall also specify the terms in any contracts associated with (a) avoidable capital expenses, normal maintenance, extraordinary maintenance and repairs, or variable costs that contain a cost, premium, and/or fee for termination of the agreement in whole or for a portion thereof, and shall provide a copy of the contract and documents pertinent to the calculation of the early termination premium, cost, and fee, and (b) revenues, and shall provide a copy of the

contract and documents pertinent to the calculation of the revenues, and the historic revenues.

31.9.7 The Market Party shall specify whether each cost is associated solely with the individual unit(s) of the Generator, or a component of the DR Proposed Service or transmission project, or whether the cost is for services or functions shared with other units or businesses. If a cost is a shared cost, the Market Party shall identify the other entities with which the cost is shared, the entity that allocates the cost to it; and the accounting protocols and methodology used in the allocation of the costs, and across which units and business the cost is allocated.

**31.9.8 Information Periods**

31.9.8.1 Information provided under Sections 31.9.2.1 and 31.9.2.2 shall encompass one year periods, for the five (5) years prior to and (a) if by an Initiating Generator for six (6) years from the date of the initial provision of information, and each annual update thereto, and (b) if by an existing Generator that is identified by the ISO pursuant to Section 31.2.11.4, for the number of years identified by the ISO in the notification provided pursuant to Section 31.2.11.4 of Attachment Y.

31.9.8.2 Information provided by proposed Gap Solutions other than an existing Generator that is identified by the ISO pursuant to Section 31.2.11.4, shall encompass one year periods, from the date of the initial provision of information for the period identified in the request of Gap Solutions.

31.9.8.3 For the financing cost of any mandatory capital expense, the Market Party shall provide information and data for: (a) the one-year period beginning on the estimated date of expenditure for the item of capital expense; and in addition (b) the period beginning on

the estimated date of expenditure for the item of capital expense and ending, respectively, (i) if an Initiating Generator two years, three years, four years, five years, and six years, from the date of the Generator Deactivation Notice; (but excluding data and information beyond the date that is six years from the Generator Deactivation Notice); (ii) if an existing Generator that is identified by the ISO pursuant to Section 31.2.11.4, for the number of years identified by the ISO in the notification provided pursuant to Section 31.2.11.4 of Attachment Y, from the date of its initial submission of information in accordance with Section 31.9.3, and (iii) if a proposed Gap Solution, for the duration of the Reliability Need identified by the ISO in its request for Gap Solutions.

## 31.10 Appendix G - Form of Reliability Must Run Agreement

# FORM OF RELIABILITY MUST RUN AGREEMENT

**Table of Contents**

**RELIABILITY MUST RUN AGREEMENT**

This RELIABILITY MUST RUN AGREEMENT ("Agreement") is made as of the_____day of _____, 20__, among ____{fill in names and types of legal entity or entities} (collectively, "Owner"), and the New York Independent System Operator, Inc., a New York not-for-profit corporation ("ISO").

RECITALS

Owner owns and has operational control over _____(PTID No. _____), a ___MW electrical Generator together with appurtenant facilities and structures, located at _____(a/the "RMR Generator"). {If the station is comprised of more than one unit, describe all units at the station, including their MW and PTIDs, and then identify each unit or sets of units that is a distinct "RMR Generator" under this Agreement}.

The ISO is the Independent System Operator for New York and is responsible for the operation of the New York Control Area ("NYCA") to ensure reliability and for the administration of the ISO Administered Markets.

Owner submitted a Generator Deactivation Notice [to mothball or to retire] each RMR Generator, which the ISO determined was complete on [ISO to fill-in date]. The Notice Period concludes or concluded on [date one year from the date that the ISO determined the Generator Deactivation Notice was complete].

The ISO has concluded that the RMR Generator[s] will be needed for reliability purposes during the Term of this Agreement. Schedule 1 to this Agreement contains a description of the Reliability Need that the RMR Generator[s] are being kept in service to address.

The Parties have agreed: [ALT. 1, IF OWNER AND ISO AGREE ON TERMS AND CONDITIONS, OWNER ACCEPTS THE APR, AND THE PARTIES EXECUTE THE AGREEMENT (i) that the ISO shall submit this executed Agreement, including the proposed Availability and Performance Rate ("APR"), to the Federal Energy Regulatory Commission ("FERC") in a Federal Power Act ("FPA") Section 205 filing on the Parties' behalf;] [ALT. 2, IF OWNER AND ISO AGREE ON TERMS AND CONDITIONS, OWNER ACCEPTS THE APR, BUT THERE ARE CAPITAL EXPENDITURES THAT REQUIRE FERC APPROVAL (i) that the ISO shall submit this Agreement to the Federal Energy Regulatory Commission ("FERC"), including the agreed-to components of a proposed Availability and Performance Rate ("APR"), in a Federal Power Act ("FPA") Section 205 filing on the Parties' behalf, and that Owner shall submit a separate FPA Section 205 filing that is consistent with the terms and conditions of service proposed in this Agreement, and that tracks the format of this Agreement, proposing the inclusion of the cost of certain Capital Expenditures in the APR;] [ALT. 3, IF OWNER AND ISO AGREE ON TERMS AND CONDITIONS BUT OWNER REJECTS THE APR AND SUBMITS AN OWNER DEVELOPED RATE (i) that the ISO shall submit this unexecuted Agreement that sets forth the Parties' agreed-upon terms and conditions of service to the Federal Energy Regulatory Commission ("FERC"), in a Federal Power Act ("FPA") Section 205 filing on the Parties' behalf, and that Owner shall submit a separate FPA Section 205 filing

proposing an Owner Developed Rate that is consistent with the terms and conditions of service proposed in this Agreement, and that tracks the format of this Agreement;] and (ii) to enter into this Agreement to establish the terms and conditions under which each RMR Generator shall be obligated to offer and provide Energy, Ancillary Services and Unforced Capacity to the ISO Administered Markets; and (iii) [to set certain components of the Availability and Performance Rate ("APR") that determines the payments by which Owner shall recover the avoidable and variable costs of each RMR Generator, and makes available possible monthly and seasonal incentive payments based on each RMR Generator's availability to operate and its performance when scheduled to operate] OR [to incorporate the Owner Developed Rate that is ultimately accepted by FERC].

NOW THEREFORE, in consideration of the agreements and covenants set forth herein, and other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, and intending to be legally bound by this Agreement as of its Start Date, the Parties covenant and agree as follows:

## ARTICLE 1 - DEFINITIONS AND RULES OF INTERPRETATION

### 1.1 Definitions.

Except for the terms defined below and in the attached schedules, capitalized terms shall be as defined in the ISO Tariffs. The definitions set forth below are only intended for use in this Agreement and shall not be relied upon to interpret the ISO's Tariffs.

1.1.1 "Additional Costs" has the meaning set forth in Section 4.3.3 of this Agreement.

1.1.2 "Affiliate" has the meaning set forth in Section 2.1 of the Services Tariff.

1.1.3 "Ancillary Services" means services necessary to support the transmission of Energy from Generators to Loads, while maintaining reliable operation of the NYS Power System in accordance with Good Utility Practice and Reliability Rules. Ancillary Services that RMR Generators may be able to provide include Voltage Support Service, Regulation Service, Operating Reserve Service (including Spinning Reserve, 10-Minute Non-Synchronized Reserves and 30-Minute Reserves), and Restoration Services (black start).

1.1.4 "Availability & Performance Rate" or "APR" means the compensation that an RMR Generator is eligible to receive in accordance with Sections 15.8.1, 15.8.3, 15.8.4 and 15.8.5 of Rate Schedule 8 to the ISO's Services Tariff during the Term of this Agreement. The APR consists of a daily calculation that is developed to permit an RMR Generator to recover its avoidable costs and variable costs, plus the opportunity to periodically earn financial incentives for availability to the markets and for performing consistent with the ISO's dispatch when scheduled.

1.1.5 "Capital Expenditures" has the meaning set forth in Section 31.2.11.8.1.3 of the OATT.

1.1.6 “Contract” means any agreement, commitment, policy, document or similar instrument creating mutual obligations among two or more parties.

1.1.7 “FERC Effective Date” has the meaning set forth in Section 2.1 of this Agreement.

1.1.8 “Force Majeure Event” has the meaning set forth in Section 8.1 of this Agreement.

1.1.9 “Forced Outage” has the meaning set forth in Section 2.6 of the Services Tariff.

1.1.10 “FPA” means the Federal Power Act (16 U.S.C. § 791a).

1.1.11 “Generator Deactivation Notice” has the meaning set forth in Section 31.1.1 of the OATT.

1.1.12 “Governmental Authority” means the government of any nation, state or other political subdivision thereof, including any entity lawfully exercising executive, military, legislative, judicial, regulatory, or administrative functions of or pertaining to a government.

1.1.13 “ISO Procedures” has the meaning set forth in Section 2.9 of the Services Tariff.

1.1.14 “ISO Tariffs” means the ISO’s Market Administration and Control Area Services Tariff (“Services Tariff”) and the ISO’s Open Access Transmission Tariff (“OATT”) collectively.

1.1.15 “Law” means any law, treaty, code, rule, regulation, or order or determination of an arbitrator, court or other Governmental Authority, or any license, permit, certificate, authorization, qualification, or approval granted by a Governmental Authority, each as amended, modified, supplemented or replaced from time to time, to the extent binding on a Party or any of its property.

1.1.16 “Market Mitigation and Analysis Department” or “MMA” has the meaning set forth in Section 30.2 of the Services Tariff.

1.1.17 “Market Monitoring Unit” or “MMU” has the meaning set forth in Section 30.2 of the Services Tariff.

1.1.18 “Month” means the period beginning at hour beginning zero on the first day of the calendar month and ending at hour beginning zero of the first day of the next succeeding calendar month.

1.1.19 “Notice of Forced Outage” has the meaning set forth in Section 7.2.3 of this Agreement.

1.1.20 “Notice of Proposed Additional Cost” has the meaning set forth in Section 31.2.11.16.1 of the OATT.

1.1.21 “Notice of Shut-down” has the meaning set forth in Section 7.2.5 of this Agreement.

1.1.22 “Order” means any determination, command, mandate or similar directive made by a Governmental Authority.

1.1.23 “Owner” has the meaning set forth in the preamble of this Agreement and, where applicable and appropriate, includes Owner’s agent, assignee and/or designee.

1.1.24 “Owner-Developed Rate” means a rate that Owner filed with the Federal Energy Regulatory Commission (“FERC”) under Section 205 of the Federal Power Act, including any modifications required by FERC in its Order accepting the rate for filing. An Owner Developed Rate is different from the ISO-developed Availability & Performance Rate. The charges that the ISO pays pursuant to an Owner Developed Rate are represented by the “RMRCost” term that is used in Rate Schedule 8 to the Services Tariff.

1.1.25 “Party” means either the ISO or Owner, as the context requires. “Parties” means ISO and Owner.

1.1.26 “Permit” means any license, certificate, authorization, qualification, or similar approval granted by a Governmental Authority empowering the grantee to do some act.

1.1.27 “Planned Outage” means a planned interruption, in whole or in part, to the availability of a Generator to permit Owner to perform maintenance and repair of the Generator.

1.1.28 “Reference Level” means the ISO’s best estimate of an RMR Generator’s incremental marginal costs, and of an RMR Generator’s physical capabilities. The ISO determines Reference Levels in accordance with the requirements of its Market Power Mitigation Measures that are set forth in Section 23 of its Services Tariff. This term does not include UCAP Offer Reference Levels.

1.1.29 “RMR Avoidable Costs” has the meaning set forth in Section 1.18 of the OATT.

1.1.30 “RMR Generator” has the meaning set forth in Section 1.18 of the OATT.

1.1.31 “Shut-down Date” has the meaning set forth in Section 7.2.9 of this Agreement.

1.1.32 “Start Date” has the meaning set forth in Section 2.1 of this Agreement.

1.1.33 “Substantiated Additional Cost” has the meaning set forth in Section 31.2.11.16.2.1 of the OATT.

1.1.34 “Term” has the meaning set forth in Section 2.1 of this Agreement.

**1.2 Interpretation**.

In this Agreement, unless otherwise indicated or otherwise required by the context, the following rules of interpretation shall apply:

1.2.1 Reference to and the definition of any document (including this Agreement, an ISO Tariff or the ISO Procedures) shall be deemed a reference to such document as it may be amended, supplemented, revised or modified from time to time, and to any document that is a successor thereto but only to the extent the amendment or other modification is not prohibited by this Agreement or the ISO's Tariffs.

1.2.2 The table of contents, article and section headings, and other captions in this Agreement are for the purpose of reference only and do not limit or affect its meaning.

1.2.3 Defined terms in the singular shall include the plural and vice versa, and the masculine, feminine or neuter gender shall include all genders.

1.2.4 The terms "include," "includes," or "including" when used herein shall not be considered limitations.

**1.3 Construction.**

1.3.1 The Parties shall comply with the ISO's Tariffs, as they may be amended from time to time.

1.3.2 This Agreement has been drafted by the Parties hereto and shall not be construed against any Party as the sole drafter.

## ARTICLE 2 – TERM

### 2.1 Start Date, FERC Effective Date and Term.

2.1.1 This Agreement shall become effective at the beginning of the hour beginning zero, on [the first day of a month] (the "Start Date") and shall terminate at the end of the operating hour beginning 23 as of the date of the termination of the [last] RMR Generator as provided in Section 2.2 ("Term"). The [Parties or filing Party] request[s] that FERC set the date that this Agreement shall become legally effective under the FPA (the "FERC Effective Date") to be consistent with the Start Date.

2.1.2 Following the ISO's submission to FERC of an executed or unexecuted Agreement: (a) commencing on the proposed Start Date the Parties shall implement and comply with the Agreement, subject to any condition or modification directed by FERC, and (b) if the Parties agree, then Owner may begin incurring costs for Capital Expenditures that are included in the Agreement for recovery pending FERC action.

### 2.2 Termination.

This Agreement may be terminated as follows:

2.2.1 Conclusion of Reliability Need. ISO may unilaterally terminate this Agreement as to [the/an] RMR Generator effective upon ninety (90) days written notice to Owner if ISO determines that [the/an] RMR Generator is no longer or will no longer be needed to meet a Reliability Need. The ninety (90) day notice may be issued by ISO at any time. If two or more RMR Generators are subject to this Agreement, the Agreement shall be terminated with respect to one or more individual RMR Generators that are no longer needed to meet a Reliability Need. Concurrent with the ISO's notice to [the/an] RMR Generator, the ISO shall inform the New

York Public Service Commission that the RMR Generator will not be needed to meet a Reliability Need after the conclusion of the ninety (90) day notice period.

2.2.2 Termination for cause. ISO may unilaterally terminate this Agreement as to [the/an] RMR Generator effective upon thirty (30) days written notice to Owner if [the/an] RMR Generator does not satisfy the Minimum Availability Standard set forth in Section 7.3.1 of this Agreement, or if [the/an] RMR Generator fails to satisfy the Minimum Performance Standard set forth in Section 7.3.2 of this Agreement, or if [the/an] RMR Generator fails to satisfy the Operation to Address the Reliability Need Standard set forth in Section 7.3.3 of this Agreement. If two or more RMR Generators are subject to this Agreement, the Agreement may be terminated with respect to one or more individual RMR Generators that have failed to satisfy a Minimum Operating Standard. The consequences of termination for cause are addressed in Section 2.2.7 of this Agreement and in Section 23.6.5 of the Services Tariff.

2.2.3 This Agreement may also be terminated for an RMR Generator as provided in Section 7.2.9 (Forced Outages), and Section 9.4 (Termination for Default).

2.2.4 This Agreement terminates as of the date that there are no longer any RMR Generators that are subject to the Agreement.

2.2.5 If this Agreement is not terminated earlier, except as set forth in Section 2.3 hereof, it shall terminate at the end of hour beginning 23 on [the End Date, which shall be the last day of a month], unless the Parties agree in writing to extend the Term because the Reliability Need has not been resolved yet.

2.2.6 Events upon termination or expiration of this Agreement. Events that will occur upon the termination or expiration of this Agreement include the following: (a) the ISO will cease

paying the APR or Owner Developed Rate (however, in some limited circumstances, the ISO may continue paying Owner for Capital Expenditures, *see* Section 4.3.2 below, or may pay wind-down costs in accordance with Section 4.8 below), (b) the RMR Generator will not be prohibited by the ISO Tariffs or this Agreement from entering a Mothball Outage or becoming Retired, consistent with the status that was indicated in a Generator Deactivation Notice and used to determine the RMR Generator's RMR Avoidable Costs or Owner Developed Rate, although such action may be subject to an audit and review, and a penalty under Sections 23.2.4.1.1, 23.3.1.1 and 23.4.5.7 of the Services Tariff; (c) where appropriate, the ISO will inform the New York State Public Service Commission that the RMR Generator will no longer be needed to meet a Reliability Need; and (d) if Owner wants an RMR Generator to continue participating in the ISO Administered Markets following the conclusion of an RMR Agreement, then Owner must provide notice to the ISO in accordance with Section 2.2.9 below and timely repay to the ISO the cost of any Capital Expenditures that must be repaid.

2.2.6.1 If the status that was indicated in a Generator Deactivation Notice and used to determine the RMR Generator's RMR Avoidable Costs or Owner Developed Rate is Retired, then Owner may elect to temporarily enter an Inactive Reserves state for up to sixty (60) days following the conclusion of an RMR Agreement before it must Retire or elect to continue participating in the ISO Administered Markets by submitting a Notice of Intent to Continue Participating in the ISO Administered Markets at Market-Based Rates in accordance with Section 2.2.9 of this Agreement and repaying the cost of any Capital Expenditures in accordance with Section 4.3.2 of this Agreement. This provision does not excuse the twenty-one (21) day prior notice requirement that applies to all Notices of Intent to Continue Participating in the ISO Administered Markets at Market-Based Rates.

2.2.6.2 Owner shall decide whether a Generator that returned from a mothball or ICAP Ineligible Forced Outage to become an RMR Generator will enter a Mothball Outage or become Retired at the conclusion of its participation in the RMR Agreement. Alternatively, Owner may elect to have such a Generator continue participating in the ISO Administered Markets by submitting a Notice of Intent to Continue Participating in the ISO Administered Markets at Market-Based Rates in accordance with Section 2.2.9 of this Agreement and repaying the cost of any Capital Expenditures in accordance with Section 4.3.2 of this Agreement. This provision does not excuse the twenty-one (21) day prior notice requirement that applies to all Notices of Intent to Continue Participating in the ISO Administered Markets at Market-Based Rates.

2.2.7 Consequence of termination of this Agreement (a) by the ISO "for cause" (*see* Section 2.2.2), or (b) due to a default by Owner (*see* Section 9.4). If the ISO terminates this Agreement for cause, or if this Agreement is terminated due to the default of Owner, following the termination date, consistent with Section 23.6.5.2 of the Services Tariff the ISO shall not be obligated by this Agreement to, and shall not continue to pay for, any Capital Expenditure that was incurred at or for a terminated RMR Generator. This includes Capital Expenditures that were included in the RMR Avoidable Cost component of an RMR Generator's APR or in an Owner Developed Rate, that were authorized for recovery as Substantiated Additional Costs by the ISO, or that were otherwise reviewed and accepted by FERC.

2.2.8 Providing notice of cancellation to FERC. The ISO shall file all required notices of cancellation with FERC, and shall seek to make such cancellations effective on the date of termination under this Agreement.

2.2.9 Notice of Intent to Continue Participating in the ISO Administered Markets at Market-Based Rates following the conclusion of this Agreement. Owner shall provide the ISO

with notice at least twenty-one (21) days in advance of the date this Agreement will terminate for an RMR Generator, identifying the RMR Generator(s) that Owner intends will continue participating in the ISO Administered Markets following the conclusion of this Agreement. If Owner intends to reduce the scope of a (former) RMR Generator's participation in the ISO Administered Markets following the conclusion of this Agreement, it may so inform the ISO in its notice. In accordance with Section 15.8.6 of Rate Schedule 8 to its Services Tariff, following the conclusion of this Agreement, the ISO shall not permit Energy, Ancillary Services or Unforced Capacity to be offered into or scheduled in the ISO Administered Markets from a former RMR Generator until all required Capital Expenditures (if any), less depreciation, have been repaid to the ISO.

**2.3 Survival.**

Notwithstanding the termination of this Agreement, the Parties shall continue to be bound by the provisions of this Agreement which by their nature are intended to, and shall, survive such termination, including Sections 3.2.4 (Refund of Insurance Proceeds), 3.3.7 (Inform Subsequent Purchaser of Repayment Obligations), 4.3.4 (Obligation to Repay Capital Expenditures), 4.7 (Penalties), 4.8 (Wind-Down Costs), 6.2 (Books and Records, Audit Rights), 7.2.8 (Refund of Insurance Proceeds), 9.2.1 and 9.2.2 (Liability), 9.2.3 (Indemnification), and 11.10 (Confidentiality). The ISO shall continue to apply Services Tariff Rate Schedule 8 and OATT Rate Schedule 14 when addressing any remaining charges, payments, credits or revenues earned or owed pursuant to this Agreement.

## ARTICLE 3 - RIGHTS AND OBLIGATIONS

### 3.1 In General.

3.1.1 During the Term, the Owner shall operate, maintain, offer and administer each RMR Generator in accordance with (a) the ISO Tariffs, (b) this Agreement, and (c) the ISO Procedures. If Owner identifies an apparent conflict between the rules it is expected to follow, it should promptly contact the ISO to resolve the concern.

3.1.2 Except as otherwise limited by this Agreement, including Section 11.1 hereof, Owner may designate one or more agents to perform its obligations under this Agreement. Actions taken by Owner's agents are considered actions by Owner. Owner shall require its agents to comply with the terms and conditions of this Agreement, and Owner shall remain primarily liable for the performance of its agents. Owner hereby ratifies and confirms all actions undertaken by its agents on behalf of Owner.

3.1.3 Owner is responsible for performing all billing obligations for each RMR Generator irrespective of whether or not it is the registered billing organization for each RMR Generator. Owner may designate or change the registered billing organization Owner relies on to fulfill these obligations in accordance with ISO Procedures.

### 3.2 Insurance.

3.2.1. At all times during the Term, Owner shall maintain insurance, written for amounts and by insurance companies acceptable to the ISO. Owner's insurance shall include (a) All Risk Property Insurance against "all risks" of physical loss or damage to the RMR Generator(s), (b) Commercial General Liability Insurance for personal injury, bodily injury, including death and property damage, and (c) Umbrella Liability Insurance.

3.2.2. Owner shall cause its insurance providers to issue endorsements (a) waiving all rights of subrogation in favor of ISO, its directors, officers, agents and employees, and (b) naming ISO as a cancellation notice recipient for all coverages.

3.2.3 Prior to the Start Date, Owner shall provide certificates of insurance for all insurance required in this Agreement. Owner shall also provide ISO with written notice of renewals, or any material changes in, or cancellation of, any required insurance policy or endorsement, no later than ten (10) days prior to the effective date thereof, including a revised certificate of insurance with evidence providing details sufficient to demonstrate Owner's continuous and uninterrupted coverage.

3.2.4 If Owner receives insurance proceeds from an insurance policy that Owner identified as an avoidable cost, and if Owner does not use those insurance proceeds to repair or improve the RMR Generator, then Owner shall make a reconciliation ("true-up") filing with the FERC and pay all such insurance proceeds to ISO that exceed the amount actually expended by the Owner to repair or improve the RMR Generator. The ISO shall distribute any insurance proceeds it receives pursuant to the requirements of this Section 3.2.4 consistent with Section 6.14.6.1 of Rate Schedule 14 to the ISO OATT.

**3.3 Contracts, Permits and Orders.**

3.3.1 Providing Contracts and Permits affecting each RMR Generator when requested by the ISO. Owner shall promptly provide a complete, up-to-date copy of any Contract, Permit or Order the ISO requests that: (a) addresses the ownership or control of an RMR Generator, (b) is relevant to determining the costs and revenues of an RMR Generator (including the cost of a repair, addition or modification), (c) addresses the operation of an RMR Generator, or (d) could impact the availability, production or sale of Energy, Unforced Capacity, or Ancillary Services

from an RMR Generator. If a Contract, Permit or Order that the ISO requests is in the process of being renewed, extended, modified or re-negotiated, Owner shall so inform the ISO when it provides the requested Contract, Permit or Order to the ISO.

3.3.2 Consistent with Section 5.12.4(c) of the Services Tariff, Owner shall not enter into any Contracts during the Term of this Agreement that would impair or otherwise diminish the ability of an RMR Generator to perform the requirements of this Agreement or of the ISO's Tariffs or Procedures, nor will Owner cause or authorize other entities to enter into a Contract that would prevent an RMR Generator from operating consistent with the requirements of this Agreement or of the ISO's Tariffs or Procedures.

3.3.3 Consistent with Sections 5.12.7, 5.12.8, 23.4.5.8.1 and 23.6.1.1 of the Services Tariff and Sections 3.5 and 3.7 of this Agreement, during the Term of this Agreement Owner shall offer all of the Energy and Ancillary Services that each RMR Generator is capable of producing directly to the ISO Administered Markets, and shall offer all of each RMR Generator's Unforced Capacity in each ICAP Spot Market Auction, unless Owner is precluded from doing so by a Contract that was in effect before Owner executed this Agreement, but only to the extent and for the duration of the obligation under such Contract.

3.3.4 Owner shall submit a summary of the key terms and conditions of all Contracts (1) that were executed prior to the execution of this Agreement, and (2) that prevent all or any portion of the Energy or Ancillary Services that one or more RMR Generator(s) are capable of producing, or prevent all or any portion of one or more RMR Generator(s) Unforced Capacity, from being offered directly to the ISO Administered Markets to FERC, along with this Agreement as part of the Federal Power Act Section 205 filing that includes this Agreement and

an APR or an Owner Developed Rate. Owner's submission must list all of the parties to each Contract and specifically identify all Affiliates with which it executed Contracts.

3.3.4.1 The following RMR Generators are subject to Contracts that predate the execution of this Agreement that affect the quantity of Energy, Ancillary Services or Unforced Capacity that will be offered directly to the ISO Administered Markets by each identified RMR Generator:

[OWNER TO ADD/PROVIDE ONE OR MORE TABLES THAT INCLUDE THE INFORMATION REQUIRED IN THE COLUMNS BELOW, SPECIFICALLY IDENTIFYING ANY AFFILIATES.]

RMR Generator Description of Contract Obligation Date Contract was Executed or Last Renewed End Date of Contract Other Parties to Contract

3.3.5 During the Term of this Agreement, Owner shall not enter into, modify, extend or renew any Contract to sell Energy, Ancillary Services or Unforced Capacity from an RMR Generator in a manner that is inconsistent with Owner's obligation to offer all of the Energy, Ancillary Services each RMR Generator is capable of producing, and to offer all of each RMR Generator's Unforced Capacity, directly to the ISO Administered Markets. The prohibition applies to the renewal of Contracts that are temporarily accommodated under Section 3.3.3 of this Agreement.

3.3.6 Transfer of ownership or control during the Term. [The/An] RMR Generator that is the subject of this Agreement may not be sold or leased, and control over [the/an] RMR Generator may not be transferred to a different entity during the Term of this Agreement unless: (a) the sale or lease receives any necessary regulatory approvals, including FERC approval under Section 203 of the FPA; (b) Owner and the entity that is purchasing or leasing the RMR Generator fully comply with all ISO Procedures that address the transfer of Generators; (c) the purchaser or lessee satisfies the ISO's credit requirements, (d) the purchaser or lessee becomes

an ISO Customer, and (e) the purchaser or lessee agrees, in writing, to assume all of Owner's obligations under this Agreement. If the transfer is temporary, or does not include the full capability of the RMR Generator owned or controlled by Owner, then Owner shall retain all of its obligations under this Agreement and the ISO Tariffs, and the purchaser or lessee shall become subject to Owner's obligations under this Agreement and the ISO Tariffs.

3.3.7 Obligation to inform subsequent purchaser of an RMR Generator of obligation to repay cost of Capital Expenditures, less depreciation, prior to re-entering ISO Administered Markets. If Owner sells an RMR Generator or an interest in an RMR Generator, during or following the Term of this Agreement, then Owner shall inform any and all purchasers of any Capital Expenditures that must be repaid before the ISO will permit Energy, Ancillary Services or Unforced Capacity to be offered into, or to be scheduled in, the ISO Administered Markets from the (former) RMR Generator following the conclusion of this Agreement with regard to that Generator.

**3.4 Testing.**

3.4.1. RMR Generators shall timely comply with all ISO requirements that are necessary for an RMR Generator to provide a product or service it is required to provide under the ISO's Tariffs or this Agreement. When necessary, Owner shall arrange in advance with the ISO, in accordance with the ISO's Outage Scheduling Manual, to self-schedule an RMR Generator in order to perform a required test.

3.4.2. If, prior to or during the twelve month Notice Period, an RMR Generator that is required to provide Voltage Support Services under Section 3.8 of this Agreement did not perform all testing that would be required to permit the RMR Generator to provide Voltage Support in the ISO Administered Markets during the Term of this Agreement, then the ISO shall require the

RMR Generator to promptly test and shall permit the RMR Generator to provide Voltage Support in the ISO Administered Markets during the Term of this Agreement, consistent with Section 15.2 of the Services Tariff.

**3.5 Energy Market Participation.**

In accordance with Sections 23.6.1.1 through 23.6.1.5 of the Services Tariff, Owner shall offer for sale into the Day-Ahead and Real-Time Markets all of the Energy and Ancillary Services each RMR Generator is capable of providing by submitting ISO-committed flexible Bids (offers) at or below (equally or less restrictive than for physical parameters) the Reference Levels that are currently on-file with the ISO and approved for use by the ISO's MMA. RMR Generators that are not Installed Capacity Suppliers, or that have not sold all of their Unforced Capacity, must still be offered into the Energy and Ancillary Services markets consistent with this obligation. *See also* Services Tariff Sections 5.12.7 and 5.12.8.

Consistent with Section 23.6.1.1 of the Services Tariff, Owner shall offer Energy, Operating Reserves and Regulation at prices that are equal to or less than each RMR Generator's ISO-approved Reference Levels. Consistent with Sections 23.6.3.1 through 23.6.3.3 of its Services Tariff, the ISO will mitigate dollar-denominated Bids that exceed an RMR Generator's currently effective Reference Levels and will perform all other Tariff-authorized mitigation.

Consistent with Sections 23.3.1.4.6.1 and 23.6.2.4 of the Services Tariff, Owner shall timely submit fuel price updates and fuel type updates to the ISO so that they can be incorporated to develop accurate Reference Levels for each RMR Generator. Submission of an inaccurate fuel price update or fuel type update may require the ISO to assess a financial penalty in accordance with Section 23.4.3.3.3 of the Services Tariff, or may result in the ISO's referral of Owner's

failure to submit accurate fuel cost information to its Market Monitoring Unit for possible referral to FERC's Office of Enforcement.

Owner is not required to submit hourly offers in the Real-Time Market for an RMR Generator that is not capable of being committed by the ISO's Real-Time Commitment ("RTC") if the RMR Generator was not committed Day-Ahead. If such an RMR Generator was committed Day-Ahead, Owner shall offer the RMR Generator into the Real-Time Market for the hours of its Day-Ahead schedule and for additional real-time hours consistent with the RMR Generator's operating capabilities. Owner is required to timely respond to a Supplemental Resource Evaluation ("SRE") or an Out-of-Merit ("OOM") commitment request issued by the ISO or by a Transmission Owner for an RMR Generator. *See* Services Tariff Sections 23.6.1.1.4 and 23.6.1.1.5.

If and to the extent an RMR Generator is not available, or is not fully available, Owner shall timely notify the ISO of the outage or derate in accordance with ISO Procedures and accurately reflect each RMR Generator's availability in its Bids. If an RMR Generator's Variable Costs change as a result of the derate, then Owner must contact the ISO's MMA Department to request changes to the RMR Generator's Reference Levels. *See* Services Tariff Sections 23.6.1.1.6.

**3.6 RMR Generator Reference Levels.**

3.6.1 In advance of the execution of this Agreement the ISO, Owner and the ISO's External Market Monitoring Unit performed a thorough review of each RMR Generator's Reference Levels consistent with Section 23.6.2.2 of the Services Tariff. Before it executed this Agreement, Owner reviewed and is aware of the Reference Levels that the ISO determined for each RMR Generator that is subject to this Agreement. During the Term of this Agreement

changes to an RMR Generator's Reference Levels shall only be made consistent with Section 23.6.2 of the Services Tariff.

3.6.2 Changes to an RMR Generator's variable costs for purposes of providing Energy, Reserves and Regulation shall be addressed via modifications to the RMR Generator's Reference Levels using the adjustment process set forth in Section 23 of the Services Tariff. Owner is responsible for ensuring that an RMR Generator's fuel costs and Reference Levels remain accurate and up-to-date. If Owner fails to provide updated information to the ISO on a timely basis mitigation, including financial penalties, may be applied in accordance with Section 23 of the Services Tariff. Failure to timely update RMR Generator information could also violate FERC's regulations. *See* 18 CFR § 1c.2(a)(2).

**3.7 Capacity Market Participation.**

3.7.1 Each RMR Generator shall perform all obligations that an Installed Capacity Supplier of its resource type is required to perform under the Services Tariff and in accordance therewith.

3.7.2 Except as set forth in Section 3.3.3 above, during the Term of this Agreement Owner shall offer all of an RMR Generator's Unforced Capacity directly into each ICAP Spot Market Auction as follows:

[ISO TO ADD ONE OR MORE TABLES SPECIFYING THE PRICE (OR SERIES OF OFFER PRICES FOR SPECIFIED QUANTITIES OF MWs) AT WHICH OWNER MUST OFFER EACH RMR GENERATOR'S UNFORCED CAPACITY FOR SPECIFIED PERIODS OF TIME DURING THE TERM OF THE RMR AGREEMENT; *I.E.*, THE RMR UCAP OFFER PRICE, DETERMINED IN ACCORDANCE WITH SECTION 23.4.5.8 OF THE SERVICES TARIFF.]

Sample Table

Start Date End Date RMR Generator PTID UCAP MW $/KwMonth

[OFFER PRICES THAT ARE NOT ZERO WILL BE MASKED/TREATED AS CONFIDENTIAL INFORMATION. IN ADDITION, UNDER ALTERNATE 3, THE ISO WILL NOT DISCLOSE THE BSM OFFER FLOOR OR THE QUANTITY OF MWs SUBJECT TO THE BSM OFFER FLOOR.]

[ALTERNATE 1 insert $0.00, unless the unit is needed for resource adequacy. If the unit is needed for resource adequacy, insert a dollar amount determined by ISO in accordance with Services Tariff Section 23.4.5.8.2.]

[ALTERNATE 2 in the circumstances specified in Section 23.4.5.8.2 of the Services Tariff, insert a dollar amount determined by ISO in accordance with Services Tariff Section 23.4.5.8.2.]

[ALTERNATE 3 if MW of the Generator are subject to an Offer Floor that is higher than the RMR UCAP Offer Price determined in accordance with Services Tariff Section 23.4.5.8.2, insert the Offer Floor and the number of MW that are subject to the Offer Floor as of the Start Date, which MW amount shall be reduced during the Term of this Agreement in accordance with the UCAP Clearing Rule. For any MW that are not subject to an Offer Floor, or if the Offer Floor is lower than the amount determined in accordance with Section 23.4.5.8.2 of the Services Tariff, then Alternate 1 or 2 above will apply.]

[ALTERNATE 4 If the RMR Generator has a pre-existing bilateral contract that satisfies the requirements of Section 3.3.3 of this Agreement, add to Section 3.7.2: For the Obligation Procurement Period of months [ ] through [ ] (the “bilateral period”), the RMR Generator shall offer {insert UCAP MW obligation and offer price consistent with the

bilateral agreement}, and (a) for any Unforced Capacity in excess of such amount and for any Obligation Procurement Period beyond the bilateral period, the Unforced Capacity shall be offered at a price of {insert ALTERNATE 1, ALTERNATE 2 or ALTERNATE 3}.]

**3.8 Restoration Services and Voltage Support Services.**

3.8.1 Each RMR Generator that provided Restoration Services (including black start service) at any time during the most recent previous twelve (12) months that it participated in the ISO Administered Markets must provide Restoration Services during the Term of this Agreement unless Owner demonstrates to the ISO that an RMR Generator is not presently capable of providing Restoration Services.

[State whether each RMR Generator will provide Restoration Services or identify the RMR Generators that will provide Restoration Services.]

3.8.2 Each RMR Generator that provided Voltage Support Service at any time during the most recent previous twelve (12) months that it participated in the ISO Administered Markets must provide Voltage Support Service during the Term of this Agreement unless Owner demonstrates to the ISO that an RMR Generator is not presently capable of providing the service.

[State whether each RMR Generator will provide Voltage Support or identify the RMR Generators that will provide Voltage Support.]

**3.9 Self-Scheduling.**

Owner is expected to offer each RMR Generator into the NYISO's Energy and Ancillary Service markets using the ISO-committed flexible bid mode at its Reference Levels for economic scheduling. However, Owner may request permission to self-schedule an RMR Generator for operational and maintenance considerations, including required testing or for fuel management

purposes. The ISO may accept or reject the requested self-schedule in its sole discretion. Variable Costs during ISO-approved self schedules will be the self-scheduled RMR Generator's Reference Levels.

## ARTICLE 4 - COMPENSATION AND SETTLEMENT

### 4.1 In General.

In lieu of receiving market compensation Owner shall receive the APR that FERC accepted for filing, [*or* Owner shall receive an Owner Developed Rate that Owner submitted to FERC under Section 205 of the Federal Power Act and that FERC accepted for filing,] including any modifications required by FERC.

[ALTERNATIVE LANGUAGE IS INCLUDED SO THAT THE *PRO FORMA* AGREEMENT CAN BE USED FOR AN AVAILABILITY AND PERFORMANCE RATE OR FOR AN OWNER DEVELOPED RATE.]

There are four components to the APR: RMR Avoidable Costs, Variable Costs, the Availability Incentive and the Performance Incentive. Each component of the APR is explained below and a rate is set forth for each component below.

The ISO will pay the APR in accordance with Rate Schedule 8 to its Services Tariff. RMR Avoidable Costs and Variable Costs are calculated daily and paid on a weekly basis. The Performance Incentive (if any) is paid on a monthly basis. The Availability Incentive (if any) is paid on a seasonal basis. When necessary, Penalties are assessed on monthly invoices.

[OWNER DEVELOPED RATE ALTERNATIVE LANGUAGE. THERE ARE TWO COMPONENTS TO AN OWNER DEVELOPED RATE. THE FIRST COMPONENT IS VARIABLE COSTS, WHICH IS DETERMINED IN THE SAME MANNER AS VARIABLE COSTS ARE DETERMINED UNDER THE APR. THE SECOND COMPONENT IS THE FERC AUTHORIZED COMPONENT. THE FERC AUTHORIZED COMPONENT EFFECTIVELY REPLACES THE RMR AVOIDABLE COST COMPONENT OF THE APR WITH THE COSTS THAT FERC AUTHORIZES FOR RECOVERY IN AN ORDER ISSUED

PURSUANT TO SECTION 205 OF THE FEDERAL POWER ACT. BECAUSE AN OWNER DEVELOPED RATE IS EXPECTED TO EXCEED AN RMR GENERATORS RMR AVOIDABLE COSTS, NO AVAILABILITY OR PERFORMANCE INCENTIVES ARE AVAILABLE.

THE ISO WILL PAY AN OWNER DEVELOPED RATE IN ACCORDANCE WITH RATE SCHEDULE 8 TO ITS SERVICES TARIFF. FERC AUTHORIZED COSTS AND VARIABLE COSTS SHALL BE CALCULATED DAILY AND PAID ON A WEEKLY BASIS.]

In addition to setting forth the APR for each RMR Generator, this Agreement sets forth the obligation of RMR Generators that are subject to an APR to pay penalties prescribed by the ISO's Tariffs, each RMR Generator's obligation to repay the cost of Capital Expenditures that were paid for under an APR or under an Owner Developed Rate, if and when the RMR Generator returns to the ISO-Administered Markets following the conclusion of this Agreement, the circumstances under which the ISO will continue to repay Capital Expenditures after an RMR Generator's obligation to provide service under this Agreement ends and the RMR Generator becomes Retired or enters a Mothball Outage, and the circumstances under which the ISO will pay wind-down costs to RMR Generators whose RMR Agreements are terminated early by the ISO due to the conclusion of the Reliability Need.

**4.2 Recovery of Variable Costs.**

Variable Costs are the incremental costs an available RMR Generator incurs to produce Energy or Ancillary Services. Variable Costs may change frequently; for example, when fuel prices change.

4.2.1. Cost of Providing Energy, Operating Reserves and Regulation

Consistent with Rate Schedule 8 to the Services Tariff, Owner shall be compensated on a weekly basis for providing Energy, Operating Reserves and Regulation based on the lesser of (a) the Bids that were submitted for an RMR Generator, or (b) the Reference Levels that are in place for an RMR Generator. The ISO will not compensate an RMR Generator for unscheduled overproduction that exceeds Compensable Overgeneration, as defined in the Services Tariff.

The ISO develops Reference Levels in accordance with Section 23 of its Services Tariff. The process the ISO uses to develop Reference Levels for each RMR Generator is described in Section 3.6 of this Agreement. The rules for changing a Reference Level that applies to an RMR Generator are set forth in Sections 23.3.1.4 and 23.6.2 of the Services Tariff.

### 4.2.2 Costs of Providing Voltage Support and Restoration Services

Voltage Support and Restoration Services (black start) are components of an RMR Generator's Variable Costs. Consistent with Rate Schedule 8 to the Services Tariff, Owner shall be compensated on a weekly basis for providing Voltage Support and/or Restoration Services. When determining the compensation an RMR Generator is eligible to receive for Voltage Support and/or Restoration Services the ISO shall treat each RMR Generator's cost of providing either service as being equal to the Tariff-authorized compensation that the ISO pays Generators for providing the service. RMR Generators that require additional or different compensation to provide Voltage Support or Restoration Services must file at FERC and obtain a different rate from FERC for providing these services.

### 4.3 Recovery of RMR Avoidable Costs.

RMR Avoidable Costs are the fixed costs that would be avoided if an RMR Generator were to exit the ISO Administered Markets in the manner described in the Generator Deactivation Notice (to enter a Mothball Outage or become Retired), including, but not limited to, mandatory capital

expenditures, fixed operating and maintenance costs, and forgone opportunity costs, determined by the ISO in accordance with Rate Schedule 8 to the Services Tariff and Section 31.2.11 of Attachment Y to the OATT, but not including variable costs and any other cost that may be included in the RMR Generator's Reference Level.

The RMR Generator-specific rates set forth below identify when each RMR Generator's RMR Avoidable Costs will change, and the amount of each change, or the expected amount of the change for Capital Expenditures. The RMR Avoidable Cost component of RMR Generator's APR may change on specific dates, or when specified milestones are met, such as the entry into service of a Capital Expenditure. In addition to the expected changes in RMR Avoidable Costs specified below, an RMR Generator's RMR Avoidable Costs may change due to the need for unexpected extraordinary maintenance or repairs (Additional Expenses) during the Term of this Agreement.

**4.3.1 Generator-Specific RMR Avoidable Costs.**

The RMR Avoidable Costs each RMR Generator that is providing service under an APR is authorized to recover are set forth in the table(s) below. However, the Capital Expenditures identified in the table(s) below are only estimates. The ISO will instead use the actual costs incurred for each Capital Expenditure to determine the APR, in accordance with Section 31.2.11.17 of Attachment Y to the OATT, as explained in Section 4.3.2 of this Agreement.

[FOR EACH RMR GENERATOR, ADD A TABLE SPECIFYING (1) THE INITIAL RMR AVOIDABLE COST (IDENTIFYING THE SIGNIFICANT COST COMPONENTS), (2) DATES WHEN, AND/OR SPECIFIC MILESTONES WHEN AVOIDABLE COSTS WILL CHANGE, SPECIFYING HOW MUCH THE COSTS WILL CHANGE (OR ARE EXPECTED TO CHANGE, WHEN THE MILESTONE IS THE IN-SERVICE DATE OF A CAPITAL

EXPENDITURE) ON EACH DATE/AT EACH MILESTONE AND BRIEFLY STATING THE REASON FOR EACH CHANGE.]

[ADDITIONAL COSTS THAT ARE FILED FOR FERC REVIEW/ACCEPTANCE SHOULD BE ADDED TO THESE TABLES.]

**4.3.2 Capital Expenditures.**

Capital Expenditures are purchases, non-operational leases of or modifications to real property and/or assets (including, but not limited to, land, buildings and equipment) that (a) are required for the continued operation of one or more RMR Generator(s) during the term of an RMR Agreement, (b) have a useful life greater than one year, and (c) are not otherwise included in the NYISO's calculation of RMR Avoidable Costs. Consistent with Section 31.2.11.17.1 of Attachment Y to the OATT, each Capital Expenditure must be distinctly identified in the tables set forth in Section 4.3.1 of this Agreement for RMR Generators that are receiving an APR, or in Section 4.6 of this Agreement for RMR Generators that are being compensated pursuant to an Owner Developed Rate. An expected cost and an expected in-service or completion date must be specified for each Capital Expenditure.

4.3.2.1 Submission of Capital Expenditures in initial FERC filing(s) by ISO and/or Owner. Consistent with Sections 31.2.11.11.3 through 31.2.11.11.5 of Attachment Y to the OATT, Capital Expenditures of $10 million per year or less (or $25 million per year or less for nuclear-powered RMR Generators) (hereafter, the "10/25 *per annum* limit") may be included in an executed RMR agreement with an APR that is filed by the ISO for FERC's review. If Capital Expenditures that exceed the 10/25 *per annum* limit are necessary in any year of the Term of this Agreement, then Owner must file separately at FERC to recover any Capital Expenditure costs that exceed the 10/25 *per annum* limit. Owner Developed Rates must separately delineate

Capital Expenditures so that the cost of Capital Expenditures can be recovered in accordance with the rules set forth in Section 31.2.11.17 of Attachment Y to the OATT.

4.3.2.2 ISO review of Capital Expenditures prior to commencing reimbursement. In accordance with Section 31.2.11.17.5 of the OATT the ISO is required to verify and validate Owner's actual expenditures. If the actual cost of a Capital Expenditure exceeds the estimate set forth in Section 4.3.1 of this Agreement by more than five (5) percent, or exceeds the Substantiated Additional Cost that was verified and validated by the ISO or the Proposed Additional Cost that was approved by FERC by more than five (5) percent, then the ISO must also review the reasonableness of the expenditure. To the extent the ISO is not able to verify and validate an expense, or if the ISO is not able to determine that the actual cost of an expenditure that exceeded the estimate presented to the ISO or to the Commission by more than five (5) percent was reasonable, then Owner must present its Capital Expenditure costs to FERC for recovery.

4.3.2.3 Reimbursement of Capital Expenditures. Consistent with Section 31.2.11.17.6.1 of the OATT, the ISO will not provide initial financing for Capital Expenditures. When an authorized or accepted Capital Expenditure enters service or is otherwise integrated into an RMR Generator, the ISO will commence reimbursing Owner for the actual, demonstrated cost of the Capital Expenditure following completion of the review process described below. Consistent with Sections 31.2.11.17.6.2 and 31.2.11.17.6.2.1 of the OATT, the ISO will reimburse Owner for each Capital Expenditure on an accelerated basis, repaying the cost of Capital Expenditures by the End Date specified in Section 2.2.5 of this Agreement.

4.3.2.4 Development of Capital Expenditures on an expedited basis. In accordance with the requirements of Section 31.2.11.16.3 of the OATT (addressing Substantiated Additional Costs

incurred during the Term of this Agreement) and Section 31.2.11.17.3 of the OATT (addressing development of a Capital Expenditure in advance of FERC action on Owner's or ISO's initial filing), when it is necessary to commence development of one or more Capital Expenditures before FERC has issued a ruling on Owner's authority to recover the cost of that or those Capital Expenditure(s), the ISO has authority to reimburse Owner for the actual costs that Owner demonstrated that it reasonably incurred constructing the Capital Expenditures up to limits of $10 million or less (or $25 million or less for nuclear-powered RMR Generators). Capital Expenditure costs that are authorized by the ISO pursuant to Section 31.2.11.16.3 of the OATT count toward the 10/25 *per annum* limit described in Section 4.3.2.1 above. Capital Expenditure costs that are authorized by the ISO pursuant to Section 31.2.11.17.3 of the OATT are not subject to the 10/25 *per annum* limit. Instead, the ISO may authorize additional expenditures of up to $10 million (or $25 million for nuclear-powered RMR Generators) each time an extraordinary event requires Owner to incur Substantiated Additional Costs. *See* Section 4.3.3 below.

4.3.2.5 ISO Approval to commence development of Capital Expenditures. In order to improve coordination between ISO and Owner, and to reduce the potential for Owner to incur costs developing a Capital Expenditure that is not needed, Owner shall obtain written approval from the ISO before it commences development of a Capital Expenditure that is scheduled to enter service more than one year after the Start Date specified in Section 2.1 of this Agreement.

4.3.2.6 Reimbursement of costs of Capital Expenditures that are not completed. If FERC issues an Order rejecting recovery of the cost of one or more Capital Expenditure(s), or if the ISO instructs Owner to cease work on a Capital Expenditure, then consistent with Sections 31.2.11.17.3 through 31.2.11.17.5 of the OATT, Owner shall promptly cease its efforts and take

reasonable steps to minimize any additional costs it incurs. If this Agreement is terminated early for an RMR Generator for reasons other than Owner's default or the RMR Generator's failure to satisfy one of the Minimum Operating Standards set forth in Section 7.3 of this Agreement, then the ISO shall reimburse the cost of Capital Expenditures that Owner was working to complete, subject to the requirements of Sections 31.2.11.17.4 and 31.2.11.17.5 of the OATT.

**4.3.3 Additional Costs.**

During the Term of this Agreement an RMR Generator that is providing service under an APR or an Owner Developed Rate may require additional Capital Expenditures or other RMR Avoidable Costs that could not have been reasonably anticipated, and are not included in or scheduled to be recovered as components of an RMR Generators RMR Avoidable Costs, or its Owner Developed Rate or its Variable Costs (hereafter, "Additional Costs").

Before it may permit recovery of Additional Costs, the ISO must first determine that (1) the Additional Costs could not have been reasonably anticipated by Owner and included in this RMR Agreement, and (2) the Additional Costs are necessary for the RMR Generator to continue to provide reliable service during the Term. The complete set of rules the ISO must follow when administering Proposed Additional Costs and Substantiated Additional Costs are set forth under Section 31.2.11.16 of the OATT.

For an RMR Generator that is providing service under an APR, the ISO is authorized by Section 31.2.11.16.3 of the OATT to allow up to $10 million (or up to $25 million for nuclear-powered RMR Generators) per event in actual, incurred and verified additional Capital Expenditures to be recovered as Substantiated Additional Costs. As with any Capital Expenditure, the ISO must limit recovery of such Substantiated Additional Costs to the actual, demonstrated costs incurred and may not begin repaying the Substantiated Additional Costs until the necessary addition,

maintenance or repair is completed or enters service. The ISO shall submit an informational filing to FERC informing FERC of any Substantiated Additional Costs it includes in an RMR Generator's APR.

Consistent with Section 31.2.11.16.4 of the OATT, Additional Costs (a) that involve RMR Avoidable Costs that are not Capital Expenditures, or (b) that exceed the ISO's authority to authorize, or (c) that the ISO is not able to verify or validate, or (d) that exceeded the cost estimate provided to the ISO or to FERC by more than 5 percent, and where the ISO is not able to determine that Owner made reasonable efforts to expend the least amount necessary, or (e) any Substantiated Additional Costs that an RMR Generator that is subject to an Owner Developed Rate must incur, are not eligible for recovery under this Agreement unless and until they are filed with and accepted by FERC.

### 4.3.4 Requirement to Repay Capital Expenditures Before the ISO May Permit a Former RMR Generator to Produce Energy, Ancillary Services or Unforced Capacity.

If, pursuant to the terms of an RMR agreement, the ISO reimbursed all or a portion of the cost of a Capital Expenditure that was incurred to permit an RMR Generator to provide service during the Term of the RMR Agreement, and the Generator is no longer the subject of this or any RMR Agreement, then before the ISO may permit the Generator to be offered into or be scheduled in the ISO Administered Markets, the cost of all Capital Expenditures that the ISO paid to enable the RMR Generator to provide service under an RMR Agreement, less depreciation, must be repaid to the ISO in accordance with the formula set forth in Section 15.8.6 of Rate Schedule 8 to the Services Tariff. Until such Capital Expenditure-related costs are repaid, the ISO shall not permit Energy, Ancillary Services or Unforced Capacity to be offered into or scheduled in the ISO Administered Markets from the Generator.

If Owner notices an RMR Generator's return to the ISO Administered Markets consistent with Section 2.2.9 of this Agreement, but does not repay Capital Expenditures, the ISO shall not permit the Generator to submit offers or receive schedules and shall place the unit in Inactive Reserve for up to sixty (60) days. If Owner has not repaid its Capital Expenditures at the end of the sixty (60) days, the ISO shall place the Generator in the state that it originally noticed (mothballed or retired). If the Generator returned from a mothball to provide RMR service, then the ISO shall return the Generator to a Mothball Outage. If the Generator returned from an IIFO to provide RMR service, then the ISO shall place the Generator in a Mothballed Outage or Retired state, at Owner's election.

**4.4 Availability Incentive.**

The baseline used to calculate the Availability Incentive each RMR Generator that is being compensated under an APR is eligible to recover is set forth in the table below. The incentive shall be calculated in accordance with Rate Schedule 8 to the Services Tariff. The ISO shall use each RMR Generator's actual availability and the baseline specified in the table below to determine the incentive (if any) it shall pay for availability over a six-month Capability Period.

[ADD TABLE SPECIFYING THE AVAILABILITY BASELINE FOR EACH RMR GENERATOR.]

**4.5 Performance Incentive.**

The baseline used to calculate the Performance Incentive each RMR Generator that is being compensated under an APR is eligible to recover is set forth in the table below. The incentive shall be calculated in accordance with Rate Schedule 8 to the Services Tariff. The ISO shall use each RMR Generator's actual performance and the baseline specified in the table below to determine the incentive (if any) it shall pay for performance each month.

[ADD TABLE SPECIFYING THE PERFORMANCE BASELINE FOR EACH RMR GENERATOR.]

**4.6 Owner Developed Rate.**

Owner Developed Rates may not exceed an RMR Generator's full cost of service. Owner must separately file its Owner Developed Rate for FERC review and acceptance.

If Owner has agreed to follow, and the ISO has separately filed the *pro forma* terms and conditions of service, then the ISO shall incorporate the accepted Owner Developed Rate, including any modifications instructed by FERC, into this Agreement after FERC issues an Order accepting the Owner Developed Rate.

The costs each RMR Generator is authorized to recover under an Owner Developed Rate are explained below (using the explanation(s) provided by Owner) and set forth in the table(s) below. The table(s) below must distinctly identify and set forth the estimated cost of each Capital Expenditure, and the date on which each Capital Expenditure is expected to enter service.

The rules for recovering the cost of Capital Expenditures under an Owner Developed Rate, including the rules that apply if an RMR Generator continues to, or returns to participate in the ISO-Administered Markets following the conclusion of this Agreement, are the same rules that apply to Generators that are compensated pursuant to an APR. *See* Section 4.3.2 of this Agreement.

RMR Generators that are compensated pursuant to an Owner Developed Rate are not eligible to receive an Availability Incentive or a Performance Incentive. RMR Generators that are compensated pursuant to an Owner Developed Rate must obtain FERC approval to recover Substantiated Additional Costs.

[OWNER TO ADD EXPLANATION OF PROPOSED OWNER-DEVELOPED RATE THAT IS CONSISTENT WITH THE REQUIREMENTS OF THIS AGREEMENT AND THE ISO'S TARIFFS, INCLUDING BUT NOT LIMITED TO THE RULES FOR IMPLEMENTING RMR RATES THAT ARE SET FORTH IN RATE SCHEDULE 8 TO THE SERVICES TARIFF AND THE RULES IN SECTION 31.2.11.17 OF THE OATT ADDRESSING THE RECOVERY OF CAPITAL EXPENDITURES. OWNER SHALL INCLUDE ONE OR MORE TABLES THAT SPECIFY THE RATE THAT WILL APPLY TO EACH RMR GENERATOR.]

**4.7 Penalties.**

Each RMR Generator that is providing service under an APR is subject to all of the potential penalties, sanctions, deficiency charges and any similar charges, except for under-generation penalties (collectively, for purposes of this paragraph, "penalties"), that may apply to Generators under the ISO Tariffs. *Provided, however*, that the total amount of penalties that can be assessed to an RMR Generator that is providing service under an APR shall be capped at the total, cumulative amount of Performance Incentive payments and Availability Incentive payments computed by the ISO to be due to that RMR Generator through the end of the month in which one or more penalties are charged.

RMR Generators that are compensated pursuant to an Owner Developed Rate are subject to all of the potential penalties, sanctions, deficiency charges and any similar charges, including under-generation penalties, that may be assessed to Generators under the ISO Tariffs, without limitation.

**4.8 Wind-Down Costs.**

If the ISO terminates this Agreement early due to the conclusion of the Reliability Need prior to the end of the Term of this Agreement (*see* Section 2.2.1 above), then the ISO shall pay any

demonstrated, actual additional wind-down costs that Owner must incur to place an RMR Generator in a Mothballed Outage or Retired state at the conclusion of this Agreement because the ISO terminated the Agreement early, in accordance with Sections 31.2.11.17.4 and 31.2.11.17.5 of the OATT. The ISO shall not pay such costs if a (former) RMR Generator continues to participate in the ISO Administered Markets following the conclusion of this Agreement. If Owner does not agree with the ISO's determination of the actual additional costs it had to incur due to the ISO's early termination of this Agreement, then Owner may submit a filing to FERC under Section 205 of the FPA seeking recovery of additional costs it will incur due to the ISO's early termination of this Agreement. The ISO may pay wind-down fees after the termination of this Agreement pursuant to Services Tariff Rate Schedule 8 and recover them from the (former) RMR LSEs under OATT Rate Schedule 14.

## ARTICLE 5 - MARKET MONITORING

### 5.1 Market Power Mitigation.

Although this Agreement requires the submission of Energy and Ancillary Service Bids for the RMR Generator(s) at fuel-adjusted Reference Levels, nothing herein shall preclude the ISO from applying any provision of its Market Power Mitigation Measures (Section 23 of the Services Tariff) to Owner, any Affiliate of Owner, the RMR Generator, or any other resources of Owner or of any Affiliate of Owner, including (a) the mitigation of Bids submitted for RMR Generators that are covered by this Agreement, and (b) conducting audits and reviews and imposing penalties pursuant to Sections 23.2.4.1.1, 23.3.1.1 and 23.4.5.7 of the Services Tariff.

The ISO's assessment of financial penalties, sanctions, deficiency charges and the like, for failure to comply with the Market Power Mitigation Measures or other provisions of the ISO's Tariffs, are addressed in Section 4.7 of this Agreement.

## ARTICLE 6 - REPORTING AND AUDIT

### 6.1 Information Access.

Owner shall maintain and shall promptly make available to ISO upon request, any books, records, documents or information in its possession or control that are necessary for ISO to: (a) audit, determine, substantiate or verify any of the costs that Owner has incurred, or that Owner is permitted to recover under this Agreement and the ISO Tariffs, and (b) carry out its responsibilities under this Agreement and its Tariffs.

### 6.2 Books and Records; Audit Rights.

6.2.1 During the Term and for six (6) years thereafter (or for a longer term, if necessary to permit the ISO to repay the cost of a Capital Expenditure), Owner shall keep detailed and accurate books and records, together with any supporting documents, pertaining to (a) the performance of its obligations under this Agreement, (b) the operation of each RMR Generator, including its availability, performance and Variable Costs, and (c) all components that went into developing the APR or the Owner-Developed Rate, including all adjustments thereto, Capital Expenditures and Substantiated Additional Costs.

6.2.2 Subject to the confidentiality requirements in Section 11.10 of this Agreement, Owner shall provide or make such books and records (including copies and extracts) available to ISO for inspection and audit at any time, upon reasonable notice.

## ARTICLE 7 - RESOURCE OPERATION AND MAINTENANCE

### 7.1 Planned Outages.

7.1.1 First year of RMR operation. The ISO and Owner have developed a planned outage schedule covering the first year of each RMR Generator's operation under this Agreement. The agreed upon schedule is included as Confidential Schedule 2 to this Agreement. The ISO will accommodate limited, reasonable changes to the agreed planned outage schedule requested by Owner, so long as such changes will not interfere with the ability of the RMR Generator to meet the Reliability Need. Planned outage schedules for subsequent years will be developed in accordance with this Article 7.

7.1.2 Owner shall be entitled to take the RMR Generator out of operation or reduce the net capability of the RMR Generator during ISO-approved Planned Outages, in accordance with the schedule for Planned Outages as established and implemented pursuant to the ISO's Outage Scheduling Manual. The ISO may amend or cancel ISO-approved Planned Outages if necessary to protect system reliability. Consistent with Section 4.4 of this Agreement and Section 15.8.4 of Rate Schedule 8 to the Services Tariff, Planned Outages may reduce the Availability Incentive (if any) paid to an RMR Generator. Performance Incentives can be earned when an RMR Generator is scheduled in real-time.

7.1.3 The ISO and the MMU shall monitor deviations from each RMR Generator's historic planned outage schedules. Owner shall promptly respond to ISO and MMU requests for explanations, information and data regarding or supporting outage schedules.

**7.2 Forced Outages.**

7.2.1 Generally. Owner shall be entitled to take the RMR Generator out of operation or reduce the net capability of the RMR Generator upon the occurrence of a Forced Outage. Consistent with Section 4.4 of this Agreement and Section 15.8.4 of Rate Schedule 8 to the Services Tariff, Forced Outages may reduce the Availability Incentive (if any) paid to an RMR Generator. Performance Incentives can be earned when an RMR Generator is scheduled in real-time.

7.2.2 The ISO and the MMU shall monitor deviations from each RMR Generator's historic forced outage rate. Owner shall promptly respond to ISO and MMU requests for explanations, information and data regarding or supporting forced outages, including the time required to return from a Forced Outage.

7.2.3 Notice of Forced Outage. In the event of a Forced Outage that is anticipated to last for more than ten (10) days, in addition to any other notification obligation arising under the ISO Tariffs and Procedures, Owner shall promptly notify the ISO, in accordance with the Outage Scheduling Manual, in writing that a Forced Outage has occurred and estimate its duration (a "Notice of Forced Outage").

7.2.4 Notice of Proposed Additional Costs. Owner shall also submit a Notice of Proposed Additional Costs to the ISO if it expects that costs that exceed the lesser of (a) $250,000, or (b) five (5) percent of annual RMR Avoidable Costs (excluding Capital Expenditures), will need to be incurred to return the RMR Generator to service, and if it satisfies the other requirements of Section 31.2.11.16.1 of the OATT. If the cost of returning an RMR Generator to service does not exceed the lesser of (a) $250,000, or (b) five (5) percent of annual RMR Avoidable Costs,

excluding Capital Expenditures, then Owner shall promptly return the RMR Generator to service without additional recompense, consistent with Section 31.2.11.16.1.1 of the OATT.

7.2.5 Notice of Shut-down. As soon as reasonably practicable after the date of a Notice of Forced Outage but in no event greater than thirty (30) days from the start of such Forced Outage, either Party may, after assessing the nature, expected duration, and expected incurrence of Proposed Additional Costs or Substantiated Additional Costs, notify the other in writing of its determination that the RMR Generator shall, subject to the provisions of Section 7.2.9 of this Agreement, be Shut-down (a "Notice of Shut-down") and if such notice applies to the entire RMR Generator that this Agreement should be terminated with regard to the affected RMR Generator.

7.2.6 In the event that an RMR Generator is Shut-down, Owner shall only be entitled to receive the APR or Owner Developed Rate through the Shut-down Date for that RMR Generator. However, the ISO may continue to repay the cost of Capital Expenditures incurred at the shut-down Generator in accordance with Section 4.3.2 of this Agreement and Section 31.2.11.17.4 of the OATT. With respect to a Shut-down applying only to some of the units that together comprise an RMR Generator, this Agreement shall remain in full force and effect with respect to the remaining unit(s).

7.2.7 Restoration following Owner Notice of Shut-down. With respect to a Notice of Shut-down made by Owner, if within thirty (30) days of receipt of Owner's Notice of Shut-down ISO provides written notice to Owner that it is willing to allow or support (as appropriate) recovery of any Substantiated Additional Costs that may be required to recover from such Forced Outage in accordance with Section 4.3.3 of this Agreement and Sections 31.2.11.16.2.1, 31.2.11.16.3, 31.2.11.16.4 and 31.2.11.17.2 of the OATT, Owner agrees that it will, with reasonable dispatch,

take the action requested by ISO, *i.e.*, not Shut-down the RMR Generator, take all actions necessary to obtain any required FERC approval, and incur the costs necessary to return the RMR Generator to service from such Forced Outage, subject to reimbursement by the ISO in accordance with Section 4.3.3 of this Agreement and Sections 31.2.11.17.5 and 31.2.11.17.6 of the OATT.

7.2.8 Owner is obligated to use its best efforts to minimize any costs it must incur, and the Substantiated Additional Costs that the ISO reimburses Owner for will be subject to offset by any proceeds from any and all third-party sources, including insurance proceeds, paid to Owner to return the RMR Generator from the Forced Outage. If Owner receives insurance proceeds or other compensation after the ISO pays Owner's Substantiated Additional Costs, then Owner shall make a subsequent reconciliation ("true-up") filing with the FERC and refund any payments to ISO for Substantiated Additional Costs that exceed the amount actually expended by the Owner, after offsets. The ISO shall distribute any insurance proceeds or other compensation it receives pursuant to the requirements of this Section 7.2.8 consistent with Section 6.14.6.1 of Rate Schedule 14 to the OATT.

7.2.9 Shut-down Date. With respect to a Notice of Shut-down issued by ISO pursuant to Section 7.2.5, the "Shut-down Date" shall be the end of hour beginning 23 at the end of the month that includes the date that is the later of (a) ten (10) days after the receipt of such Notice of Shut-down by the Owner, or (b) sixty (60) days after the Forced Outage began. With respect to a Notice of Shut-down issued by Owner pursuant to Section 7.2.5, the Shut-down Date shall be the end of the month that includes the date that is the later of (x) thirty (30) days after the receipt of such Notice of Shutdown by ISO, or (y) sixty (60) days after the Forced Outage began, unless ISO has agreed to pay Owner's Substantiated Additional Costs in accordance with Section 7.2.7,

in which case no Shut-down Date will have occurred with respect to such Notice of Shut-down. As of the Shut-down Date, Owner may place the former RMR Generator in an ICAP Ineligible Forced Outage or reclassify the former RMR Generator's status to Retired.

### 7.3 Minimum Operating Standards.

The requirements set forth below specify the Minimum Availability, Minimum Performance and Operation to Address the Reliability Need Standards that each RMR Generator is expected to achieve in order to continue to be entitled to compensation under this Agreement, including recovery of the cost of Capital Expenditures and Additional Costs.

#### 7.3.1 Minimum Availability Standards.

The ISO developed the Minimum Availability Standard(s) set forth below for each RMR Generator based on (a) the RMR Generator's historical performance, (b) any deferred maintenance, repair or capital expenditure costs that are included in RMR Avoidable Costs for an RMR Generator that can reasonably be expected to improve the RMR Generator's availability, and (c) other factors that are specific to the particular RMR Generator for which the Minimum Availability Standard was developed.

[ADD TABLE WITH THE MINIMUM AVAILABILITY STANDARD THAT THE ISO WILL APPLY TO EACH RMR GENERATOR THAT IS SUBJECT TO THE RMR AGREEMENT.]

#### 7.3.2 Minimum Performance Standards.

The ISO developed the Minimum Performance Standard(s) set forth below for each RMR Generator based on (a) the RMR Generator's historical performance when scheduled to operate in real-time by the ISO, (b) any deferred maintenance, repair or capital expenditure costs that are included in RMR Avoidable Costs for an RMR Generator that can reasonably be expected to improve the RMR Generator's performance, and (c) other factors that are specific to the

particular RMR Generator for which the Minimum Performance Standard was developed. [ADD TABLE WITH THE MINIMUM PERFORMANCE STANDARD THAT THE ISO WILL APPLY TO EACH RMR GENERATOR THAT IS SUBJECT TO THE RMR AGREEMENT.]

### 7.3.3 Operation to Address the Reliability Need Standard.

If an RMR Generator fails to operate as requested when it is called upon by the ISO or by a Transmission Owner to address the Reliability Need that is described in Schedule 1 to this Agreement on three or more occasions over the Term of this Agreement, then the ISO may terminate this Agreement as to that RMR Generator.

## ARTICLE 8 - FORCE MAJEURE EVENTS

### 8.1 Definition of Force Majeure Event.

"Force Majeure Event" shall mean a cause or occurrence preventing a Party from performing its obligations under this Agreement, which cause or occurrence is beyond the reasonable control of the Party affected, not reasonably foreseeable by such Party, not due to an act or omission of the Party affected, and which could not have been avoided by the exercise of reasonable diligence. A Force Majeure Event shall not include any economic hardship, the cost of or inability to procure fuel, or changes in market conditions that affect the price of energy or transmission.

### 8.2 Notice of Force Majeure Event.

If any Party is unable to perform its obligations under this Agreement due to a Force Majeure Event, the Party that is unable to perform shall promptly notify the other Party of this occurrence, the effect on its performance, the nature of any corrective action needed, its efforts to remedy its inability to perform, and when it estimates it will be able to resume performance. Thereafter the nonperforming Party shall update that information as reasonably necessary.

### 8.3 Effect of Force Majeure Event.

If a Force Majeure event results in a Forced Outage then Sections 7.2.1. through 7.2.9 of this Agreement shall apply. If a Force Majeure Event prevents a Party from complying with any one or more obligations under this Agreement, that inability to comply will not constitute a default if (a) that Party uses reasonable efforts to remediate the Force Majeure Event in accordance with Section 8.4, and (b) that Party complies with its notice obligations under Section 8.2.

**8.4 Remedial Efforts.**

If a Force Majeure Event occurs, the Party unable to perform by reason of that Force Majeure Event shall use reasonable efforts to resume its performance under this Agreement as soon as practicable, to mitigate the consequences of the Force Majeure Event, and to limit damages to the other Party; provided that no Party shall be required to settle any strike, walkout, lockout, or other labor dispute on terms which, in the Party's sole discretion, are contrary to its interests.

## ARTICLE 9 - DISPUTE RESOLUTION AND REMEDIES

### 9.1 Dispute Resolution.

The Parties shall make reasonable efforts to settle any dispute arising out of or in connection with this Agreement. The process and timeframe for Owner to challenge invoices related to this Agreement is set forth in Section 7.4 of the Services Tariff. For all other disputes, the Parties shall designate officers or other senior representatives to confer and attempt to resolve a dispute on an informal basis within two (2) calendar days after receiving written notice of a dispute. If the Parties are unable to resolve the dispute by mutual agreement within ten (10) business days after receiving written notice of a dispute (such period may be extended by the mutual, written agreement of the Parties), then the dispute may be referred to FERC's Dispute Resolution Division by either Party.

### 9.2 Liability and Indemnification.

9.2.1 Liability of ISO. The ISO shall not be liable, whether based on contract, indemnification, warranty, equity, tort, strict liability or otherwise, to Owner or any third party or other person for any damages whatsoever arising or resulting from any actions or omissions by ISO in performing its obligations under this Agreement, except to the extent ISO is found liable for gross negligence or willful misconduct, in which case ISO will only be liable for direct damages.

9.2.2 Liability of Owner. Except as set forth in Section 4.7 (Penalties) of this Agreement, or as set forth in the ISO's Tariffs, in no event shall Owner be liable to ISO for any incidental, consequential, multiple or punitive damages, loss of revenues or profits, attorneys fees or costs arising out of, or connected in any way with the performance or non-performance of this Agreement except to the extent Owner is found liable for gross negligence or willful misconduct.

9.2.3 Indemnification. Owner shall indemnify, defend and save harmless the ISO and its directors, officers, employees and agents from any and all damages, losses, claims and liabilities by or to third parties arising out of or resulting from the performance by ISO under this Agreement or the actions or omissions of Owner in connection with this Agreement, except in cases of gross negligence or willful misconduct by the ISO or its directors, officers, employees or agents.

**9.3 Specific Performance.**

The Parties agree that irreparable damage would occur in the event that any of the provisions of this Agreement were not performed in accordance with their specific terms and that monetary damages alone, even if available, would not be an adequate remedy. It is accordingly agreed that the Parties shall be entitled to specific performance of the terms hereof, this being in addition to any other remedy to which they are entitled at Law or in equity.

**9.4 Termination for Default.**

If any Party shall fail to perform any material obligation imposed on it by this Agreement and that obligation has not been suspended pursuant to this Agreement, the other Party, at its option, may terminate this Agreement by giving the Party in default written notice setting out specifically the circumstances constituting the default and declaring its intention to terminate this Agreement. If the Party receiving the notice does not within ten (10) days after receiving the notice, remedy the default, the Party not in default shall be entitled by a further written notice to terminate this Agreement. The Party not in default shall have a duty to mitigate damages. Termination of this Agreement pursuant to this Section 9.4 shall be without prejudice to the right of any Party to collect any amounts due to it under this Agreement.

**9.5 Waiver.**

The failure to exercise any remedy or to enforce any right provided in this Agreement or applicable Law shall not constitute a waiver of such remedy or right or of any other remedy or right. A Party shall be considered to have waived any remedies or rights only if the waiver is in writing. A waiver given by a Party will be applicable only to the specific instance for which it is given.

**9.6 No Third-Party Beneficiaries.**

Except as is specifically set forth in this Agreement, nothing in this Agreement, whether express or implied, confers any rights or remedies under, or by reason of, this Agreement on any persons other than the Parties and their respective successors and permitted assigns, nor is anything in this Agreement intended to relieve or discharge the obligations or liability of any third party, nor give any third person any rights of subrogation or action against any Party.

**9.7 Remedies Cumulative.**

The rights and remedies of the Parties are cumulative and not alternative.

## ARTICLE 10 - COVENANTS OF THE PARTIES

**10.1 ISO represents and warrants to Owner as follows:**

10.1.1 The ISO is a validly existing corporation with full authority to enter into this Agreement.

10.1.2 The ISO has full power and authority to enter into this Agreement and perform all of the ISO's obligations, representations, warranties, and covenants under this Agreement.

10.1.3 The ISO has taken all necessary measures to have the execution and delivery of this Agreement authorized, and upon the execution and delivery of this Agreement, this Agreement shall be a legally binding obligation of the ISO.

10.1.4 The ISO has all regulatory authorizations necessary for it to perform its obligations under this Agreement.

10.1.5 The execution, delivery, and performance of this Agreement are within ISO's powers and do not violate any of the terms and conditions in its governing documents, any contracts to which it is a party, or any Law applicable to it.

**10.2 Owner represents and warrants to ISO as follows:**

10.2.1 Owner is duly organized, validly existing and in good standing under the Laws of the jurisdiction under which it is organized, and is authorized to do business in New York.

10.2.2 Owner has full power and authority to enter into this Agreement and to perform (directly, or through its agents and assigns that are authorized pursuant to Section 11.1 of this Agreement) all of Owner's duties, obligations, representations, warranties, and covenants under this Agreement, including the power to offer Energy, Unforced Capacity, and Ancillary Services

from each RMR Generator, and to operate, maintain, and administer each RMR Generator, all in accordance with (a) the ISO Tariffs, (b) this Agreement, and (c) the ISO Procedures.

10.2.3 Owner has taken all necessary measures to have the execution and delivery of this Agreement authorized, and upon the execution and delivery of this Agreement, this Agreement shall be a legally binding obligation of Owner.

10.2.4 Owner possesses, or has applied for, all regulatory authorizations, necessary for it to perform its obligations under this Agreement.

10.2.5 The execution, delivery, and performance of this Agreement are within the Owner's powers and do not violate any of the terms and conditions in its governing documents, any contracts to which it is a party, or any Law applicable to it.

10.2.6 Owner is not in violation of any Laws, ordinances, or governmental rules, regulations or Order of any Governmental Authority or arbitration board materially affecting the performance of this Agreement.

10.2.7 Owner is not bankrupt, does not contemplate becoming bankrupt nor, to its knowledge, will become bankrupt.

10.2.8 Owner is an ISO Customer [and an ISO Transmission Customer,] and acknowledges that it has reviewed and is familiar with the ISO Tariffs.

10.2.9 Owner acknowledges and affirms that the foregoing representations, warranties, and covenants are continuing in nature throughout the Term of this Agreement. For purposes of this Section, "materially affecting performance" means resulting in a materially adverse effect on Owner's performance of its obligations under this Agreement.

## ARTICLE 11 - MISCELLANEOUS PROVISIONS

### 11.1 Assignment.

A Party shall not assign its rights or delegate its duties under this Agreement without the prior written consent of the other Party. Any such assignment or delegation made without such written consent shall be null and void. Upon any assignment made in compliance with this Section 11.1, this Agreement shall inure to and be binding upon the successors and assigns for the assigning Party.

### 11.2 Notices.

Except as otherwise expressly provided in this Agreement or required by Law, all notices, consents, requests, demands, approvals, authorizations and other communications provided for in this Agreement shall be in writing and shall be sent by personal delivery, certified mail, return receipt requested, facsimile transmission, electronic mail, or by recognized overnight courier service, to the intended Party at such Party's address set forth below. All such notices shall be deemed to have been duly given and to have become effective: (a) upon receipt if delivered in person, by facsimile, or by electronic mail; (b) two days after having been delivered to an air courier for overnight delivery; or (c) seven days after having been deposited in the United States mail as certified or registered mail, return receipt requested, all fees pre-paid, addressed to the applicable addresses set forth below. Each Party's address for notices shall be as follows (subject to change by notice in accordance with the provisions of this Section 11.2):

If to Owner:

[OFFICER NAME]

[OFFICER TITLE]

[STREET ADDRESS]

[CITY, STATE, ZIP]

[PHONE NUMBER]

[FAX NUMBER]

[E-MAIL ADDRESS]

If to ISO:

[OFFICER NAME]

[OFFICER TITLE]

10 Krey Boulevard

Rensselaer, New York 12144

[PHONE NUMBER]

[FAX NUMBER]

[E-MAIL ADDRESS]

With a copy to:

[INSERT LEGAL CONTACT]

The persons designated to receive Notice for a Party may be modified by providing Notice to the other Party of a change.

**11.3 Parties' Representatives.**

Owner and the ISO shall ensure that throughout the Term of this Agreement, duly appointed representatives are available for communications between the Parties. The representatives shall have full authority to deal with all day-to-day matters arising under this Agreement. Acts and omissions of representatives shall be deemed to be acts and omissions of the Party. Owner and ISO shall be entitled to assume that the representatives of the other Party are at all times acting within the limits of the authority given by the representatives' Party. Owner's representatives shall be identified on Exhibit A. The ISO's representatives shall be identified on Exhibit B. The Parties may at any time replace their representatives by sending the other Party a revision to its respective Exhibit.

**11.4 Effect of Invalidation, Modification, or Condition.**

Each covenant, condition, restriction, and other term of this Agreement is intended to be, and shall be construed as, independent and severable from each other covenant, condition, restriction, and other term. If any covenant, condition, restriction, or other term of this Agreement is held to be invalid or otherwise modified or conditioned by any Governmental Authority, the invalidity, modification, or condition of such covenant, condition, restriction, or other term shall not affect the validity of the remaining covenants, conditions, restrictions, or other terms hereof. If an invalidity, modification, or condition has a material impact on the rights and obligations of the Parties, the Parties shall make a good faith effort to renegotiate and restore the benefits and

burdens of this Agreement as they existed prior to the determination of the invalidity, modification, or condition.

**11.5 Amendments.**

Amendments or modifications of this Agreement may be made only by a written instrument duly executed by all Parties, or through a filing with FERC under Section 206 of the FPA. Mutually agreed to amendments or modifications shall become effective only after the Parties have received any authorizations required from FERC. The Parties agree to negotiate in good faith any amendments to this Agreement that are needed to reflect the intent of the Parties as expressed herein and to reflect any changes to the design of the ISO Administered Markets that are approved by the Commission from time to time. Alternatively, either Party shall have the right to make a unilateral filing with FERC to modify this Agreement pursuant to Section 206 of the FPA and FERC's rules and regulations thereunder. The Parties agree that any such filing shall not be subject to the "public interest" application of the just and reasonable standard of review as clarified in *Morgan Stanley Capital Group, Inc. v. Public Util. Dist. No. 1 of Snohomish County, Washington*, 554 U.S. 527 (2008) and refined in *NRG Power Mktg. v. Maine Pub. Utils. Comm'n*, 130 S. Ct. 693, 700 (2010). Each Party shall have the right to protest any such filing by another Party and to participate fully in any proceeding before FERC in which such modifications may be considered.

Nothing in this Section 11.5 shall be interpreted to require the ISO's concurrence before Owner may submit a filing under Section 205 of the FPA to propose an initial rate to FERC, or to recover costs that Owner (or an RMR Generator) is specifically authorized to submit or to seek to recover under Sections 31.2.11.1 to 31.2.11.17 of the OATT. Nothing in this Section 11.5 shall be interpreted to require Owner's concurrence before the ISO may submit a filing under

Section 205 of the FPA to comply with the requirements of its Tariffs, or to submit a filing in accordance with Sections 2.2.8 or 4.6 of this Agreement.

**11.6 Governing Law.**

This Agreement shall be governed by and construed under the Laws of the State of New York without regard to conflicts of laws principles.

**11.7 Entire Agreement.**

This Agreement, as well as any appendices, schedules, exhibits or other attachments hereto, which are incorporated by reference herein and made a part hereof, constitutes the entire agreement between the Parties with respect to the subject matter hereof and supersedes all prior negotiations, undertakings, agreements and understandings.

**11.8 Independent Contractors.**

Owner and ISO acknowledge that as between Owner and ISO there is an independent contractor relationship, and that nothing in this Agreement shall create any association, joint venture, partnership, or principal/agent relationship between the Parties. Neither Owner nor ISO shall have any right, power, or authority to enter into any agreement or commitment, act on behalf of, or otherwise bind the other Party in any way.

**11.9 Counterparts.**

This Agreement may be executed in one or more counterparts each of which shall be deemed an original and all of which shall be deemed one and the same agreement.

**11.10 Confidentiality.**

Confidential Information or Protected Information identified as such by a Party and provided to the other Party pursuant to this Agreement shall be governed by the confidentiality provisions in

the Code of Conduct, contained in Attachment F of the OATT, and the confidentiality provisions in the Market Monitoring Plan, contained in Attachment O of the Services Tariff, subject to the following:

11.10.1 Nothing herein or therein shall limit the right of a Party to file a copy of this Agreement with the Commission, without redaction, to the extent that Law, regulation, or agency Order makes such filing necessary or appropriate.

11.10.2 Notwithstanding anything in this Agreement to the contrary, if during the course of an investigation or otherwise, the Commission requests that a Party (the "responding Party") provide to it information that has been designated by the other Party to be treated as confidential under this Agreement, the responding Party shall provide the requested information to the FERC or its staff within the time provided for in the request for information. The responding Party shall, consistent with 18 CFR § 388.112, request that the information be treated as confidential and non-public by the FERC and its staff and that the information be withheld from public disclosure.

**11.11 Further Assurances.**

The Parties agree to do such further acts and things and to execute and deliver such additional agreements and instruments as may be reasonably necessary to carry out the provisions and purposes of this Agreement.

**11.12 Submittal to the Commission.**

The Parties acknowledge and agree [ALT. 1, IF OWNER AND ISO AGREE ON TERMS AND CONDITIONS AND OWNER ACCEPTS THE APR that the ISO shall submit the executed Agreement to the FERC, including the proposed APR, in a FPA Section 205 filing on the Parties' behalf;] [ALT. 2, IF OWNER AND ISO AGREE ON TERMS AND CONDITIONS, OWNER

ACCEPTS THE APR, BUT THERE ARE CAPITAL EXPENDITURES THAT REQUIRE FERC APPROVAL (i) that the ISO shall submit this Agreement to the FERC, including the agreed-to components of the proposed APR, in a FPA Section 205 filing on the Parties' behalf, and that Owner will submit a separate FPA Section 205 filing that is consistent with the terms and conditions of service proposed in this Agreement, and that tracks the format of this Agreement, proposing the inclusion of the cost of certain Capital Expenditures in the APR;]

[ALT. 3, IF OWNER AND ISO AGREE ON TERMS AND CONDITIONS BUT OWNER REJECTS THE APR AND SUBMITS AN OWNER DEVELOPED RATE that the ISO shall submit the Parties' agreed-upon terms and conditions of service to the FERC, in a FPA Section 205 filing on the Parties' behalf, and that Owner will submit a separate FPA Section 205 filing proposing an Owner Developed Rate that is consistent with the terms and conditions of service proposed in this Agreement and that tracks the format of this Agreement.]

Following the ISO's submission to FERC of an executed or unexecuted Agreement, the Parties will implement and comply with this Agreement in accordance with Section 2.1.2 hereof.

**IN WITNESS WHEREOF**, this Agreement has been executed as of the date first above written.

[OWNER NAME]

By: _____

Name:

Title:

NEW YORK INDEPENDENT SYSTEM OPERATOR, INC.

By: _____

Name:

Title:

## EXHIBIT A - OWNER'S REPRESENTATIVES

[OWNER TO PROVIDE]

**EXHIBIT B - ISO'S REPRESENTATIVES**

[NAME OF NYISO OFFICER WITH AUTHORITY TO EXECUTE AN RMR AGREEMENT]

[OFFICER TITLE] New York Independent System Operator, Inc.

10 Krey Boulevard

Rensselaer, New York 12144