ATTACHMENT J

DETERMINATION OF DAY-AHEAD MARGIN ASSURANCE PAYMENTS

1.0 General Rule

If an eligible Supplier buys out of a Day-Ahead Energy, Regulation Service or Operating Reserve schedule in a manner that reduces its Day-Ahead Margin it shall receive a Day-Ahead Margin Assurance Payment, except as noted in Sections 4.0, and 5.0 of this Attachment J. The purpose of such payments is to protect Suppliers' Day-Ahead Margins associated with real-time reductions after accounting for: (i) any real-time profits associated with offsetting increases in real-time Energy, Regulation Service, or Operating Reserve Schedules; and (ii) any Supplier-requested real-time de-rate granted by the ISO.

2.0 Eligibility for Receiving Day-Ahead Margin Assurance Payments

The following categories of Suppliers shall be eligible to receive Day-Ahead Margin Assurance Payments: (i) all Self-Committed Flexible and ISO-Committed Flexible Generators that are online and dispatched by RTD; (ii) Demand Side Resources committed to provide Operating Reserves or Regulation Service; (iii) any Supplier that is scheduled out of economic merit order by the ISO in response to an ISO or Transmission Owner system security need or to permit the ISO to procure additional Operating Reserves; (i~~ii~~v) any Supplier that is derated or decommitted by the ISO in response to an ISO or Transmission Owner system security need or to permit the ISO to procure additional Operating Reserves; and (~~i~~v) Energy Limited Resources with a total margin for the dispatch day that is less than its Day-Ahead margin as a result of an ISO-approved real-time reduction in scheduled output from its Day-Ahead schedule for Energy limited reasons.

3.0 ~~3.0~~ Calculation of Day-Ahead Margin Assurance Payments

3.01 Day-Ahead Margin Assurance Payments for ~~Suppliers~~Generators shall be determined by applying the following equations to each individual Generator using the terms as defined in subsection 3.03:~~(or, when applicable, to each individual Demand Side Resource)~~:

$$DMAP_{hu} = \max\left(0, \sum_{i \in h} CDMAP_{iu}\right) \text{where:}$$

$$CDMAP_{iu} = CDMAPen_{iu} + \sum_{p} CDMAPres_{iup} + CDMAPreg_{iu},$$

If the Supplier's ~~-~~real-time Energy schedule is lower than its Day-Ahead Energy schedule then:

$$CDMAPen_{iu} = \left\{ \begin{array}{c} [DASen_{hu} - LL_{iu}] \times RTPen_{iu} \\ - \int_{LL_{iu}}^{DASen_{hu}} DABen_{hu} \end{array} \right\} * \frac{Seconds_i}{3600},$$

If the Supplier's real-time Energy schedule is greater than or equal to its Day-Ahead Energy schedule then:

$$CDMAPen_{iu} = MIN\left(\left\{ \begin{array}{c} [DASen_{hu} - UL_{iu})] \times RTPen_{iu} \\ + \int_{DASen_{hu}}^{UL_{iu}} RTBen_{iu} \end{array} \right\} * \frac{Seconds_i}{3600}, 0 \right)$$

If the Supplier's real-time schedule for a given Operating Reserve product, p, is lower than its Day-Ahead Operating Reserve schedule for that product then:

$$CDMAPres_{iup} = [(DASres_{hup} - RTSres_{iup}) \times (RTPres_{iup} - DABres_{hup})] * \frac{Seconds_i}{3600}$$

If the Supplier's real-time schedule for a given Operating Reserve product, p, is greater than or equal to its Day-Ahead Operating Reserve schedule for that product then:

$$CDMAPres_{iup} = [(DASres_{hup} - RTSres_{iup}) \times (RTPres_{iup})] * \frac{Seconds_i}{3600}$$

If the Supplier's real-time Regulation Service schedule is less than its Day-Ahead Regulation Service schedule then:

$$CDMAPreg_{iu} = [(DASreg_{hu} - RTSreg_{iu}) \times (RTPreg_{iu} - DABreg_{hu})] * \frac{Seconds_i}{3600}$$

If the Supplier's real-time Regulation Schedule is greater than or equal to the Day-Ahead Regulation Service schedule then:

$$CDMAPreg_{iu} = [(DASreg_{hu} - RTSreg_{iu}) \times MAX((RTPreg_{iu} - RTBreg_{iu}),0)] * \frac{Seconds_i}{3600} .;$$

3.02. Day-Ahead Margin Assurance Payments for Demand Side Resources scheduled to provide Operating Reserves or Regulation Service shall be determined by applying the following equations to each individual Demand Side Resource using the terms as defined in subsection 3.03:

$$DMAP_{hu} = \max\left(0, \sum_{i \in h} CDMAP_{iu}\right) \text{ where:}$$

$$CDMAP_{iu} = \sum_{p} CDMAPres_{iup} + CDMAPreg_{iu} .$$

If the Demand Side Resource's real-time schedule for a given Operating Reserve product, p, is lower than its Day-Ahead Operating Reserve schedule for that product then:

$$CDMAPres_{iup} = [(DASres_{hup} - RTSres_{iup}) \times (RTPres_{iup} - DABres_{hup})] * RPIiu * \frac{Seconds_i}{3600}$$

If the Demand Side Resource's real-time schedule for a given Operating Reserve product, p, is greater than or equal to its Day-Ahead Operating Reserve schedule for that product then:

$$CDMAPres_{iup} = \left[\left(DASres_{hup} - RTSres_{iup}\right) \times \left(RTPres_{iup}\right)\right] * RPI\ iu * \frac{Seconds_i}{3600}$$

If the Demand Side Resource's real-time Regulation Service schedule is less than its Day-Ahead Regulation Service schedule then:

$$CDMAPreg_{iu} = \left[\left(DASreg_{hu} - RTSreg_{iu}\right) \times \left(RTPreg_{iu} - DABreg_{hu}\right)\right] * \frac{Seconds_i}{3600}$$

If the Demand Side Resource's real-time Regulation Schedule is greater than or equal to the Day-Ahead Regulation Service schedule then:

$$CDMAPreg_{iu} = \left[\left(DASreg_{hu} - RTSreg_{iu}\right) \times MAX\left(\left(RTPreg_{iu} - RTBreg_{iu}\right), 0\right)\right] * \frac{Seconds_i}{3600}.$$

3.03 Terms used is this Attachment J:

~~where:~~

h is the hour that includes interval *i*;

$DMAP_{hu}$ = the Day-Ahead Margin Assurance Payment attributable in any hour *h* to any Supplier *u*;

$CDMAP_{iu}$ = the contribution of RTD interval *i* to the Day-Ahead Margin Assurance Payment for Supplier *u*;

$CDMAPen_{iu}$ = the Energy contribution of RTD interval *i* to the Day-Ahead Margin Assurance Payment for Supplier *u*;

$CDMAPreg_{iu}$ = the Regulation Service contribution of RTD interval *i* to the Day-Ahead Margin Assurance Payment for Supplier *u*;

$CDMAPres_{iup}$ = the Operating Reserve contribution of RTD interval *i* to the Day-Ahead Margin Assurance Payment for Supplier *u* determined separately for each Operating Reserve product p;

$DASen_{hu}$ = Day-Ahead Energy schedule for Supplier *u* in hour *h*;

$DASreg_{hu}$ = Day-Ahead schedule for Regulation Service for Supplier *u* in hour *h*;

$DASres_{hup}$ = Day-Ahead schedule for Operating Reserve product p, for Supplier *u* in hour *h*;

$DABen_{hu}$ = Day-Ahead Energy bid curve for Supplier *u* in hour *h*;

$DABreg_{hu}$ = Day-Ahead Availability Bid for Regulation Service for Supplier *u* in hour *h*;

$DABres_{hup}$ = Day-Ahead Availability Bid for Operating Reserve product p for Supplier *u* in hour *h*;

$RTSen_{iu}$ = Real-time Energy scheduled for Supplier *u* in interval *i*, and calculated as the arithmetic average of the 6-second AGC Base Point Signals sent to Supplier *u* during the course of interval *i*;

$RTSreg_{iu}$ = Real-time schedule for Regulation Service for Supplier *u* in interval *i*.

$RTSres_{iup}$ = Real-time schedule for Operating Reserve product p for Supplier *u* in interval *i*.

$RTBreg_{iu}$ = Real-time Availability Bid for Regulation Service for Supplier *u* in interval *i*.

$RTBen_{iu}$ = Real-time Energy bid curve for Supplier *u* in interval *i*.

AEI_{iu} = average Actual Energy Injection by Supplier u in interval *i* but not more than $RTSen_{iu}$ plus Compensable Overgeneration;

$RTPen_{iu}$ = real-time price of Energy at the location of Supplier *u* in interval *i*;

$RTPreg_{iu}$ = real-time price of Regulation Service at the location of Supplier *u* in interval *i*;

$RTPres_{iup}$ = real-time price of Operating Reserve product p at the location of Supplier *u* in interval *i*;

LL_{iu} = max ($RTSen_{iu}$, min(AEI_{iu},EOP_{iu})), but not more than $DASen_{hu}$ if $RTSen_{iu} < EOP_{iu}$ and min ($RTSen_{iu}$, max(AEI_{iu},EOP_{iu})), but not more than $DASen_{hu}$ otherwise;

UL_{iu} = min ($RTSen_{iu}$, max(AEI_{iu},EOP_{iu})) but not less than $DASen_{hu}$ if $RTSen_{iu} \geq EOP_{iu} \geq DASen_{hu}$ and max ($RTSen_{iu}$, min(AEI_{iu},EOP_{iu})) but not less than $DASen_{hu}$ otherwise;

EOP_{iu} = the Economic Operating Point of Supplier *u* in interval *i* calculated without regard to ramp rates;

$Seconds_i$ = number of seconds in interval *i*

RPIiu = the Reserves Performance Index in interval i for Demand Side Resource u. The Reserves Performance Index is calculated pursuant to Section 3.6 of Rate Schedule 4 of this Services Tariff.

3.04 Other Provisions

The AGC Base Point Signal for a ~~Generator~~Supplier that is not providing Regulation Service during a given RTD interval shall be initialized by either: (i) the ~~Generator's~~ Supplier's last AGC Base Point Signal from the prior RTD interval; or (ii) the ~~Generator's~~Supplier's actual metered generation or calculated Demand Reduction at the time new RTD Base Point Signals are received by the ISO's AGC software, whichever is closer to the ~~Generator's~~Supplier's new RTD Base Point Signal. AGC Base Point Signals for a ~~Generator~~ Supplier that is not providing Regulation Service will ramp evenly over the course of the RTD interval starting at the initialized AGC Base Point Signal and ending at the level of its new RTD Base Point Signal. AGC Base Point Signals for ~~Generators~~ Suppliers providing Regulation Service during a given RTD interval are determined based on the ISO's need to minimize the NYCA area control error.

4.0 Exception for ~~Suppliers~~ Generators Lagging Behind RTD Base Point Signals

An otherwise eligible ~~Supplier~~ Generator that does not respond to, or that lags behind, the ISO's RTD Base Point Signals in a given interval, as determined below, shall not be eligible for Day-Ahead Margin Assurance Payments for that interval. If such a ~~Supplier's~~ Generator's average Actual Energy Injection in an RTD interval (*i.e.*, its Actual Energy Injections averaged over the RTD interval) is less than or equal to its penalty limit for under-generation value for that interval, as computed below, it shall not be eligible for Day-Ahead Margin Assurance Payments for that interval.

The penalty limit for under-generation value is the tolerance described in Section 1.0 of Rate Schedule 3-A of this ISO Services Tariff, which is used in the calculation of the persistent under-generation charge applicable to ~~Suppliers~~ Generators that are not providing Regulation Service.

4.0 ~~5.0~~ Rules Applicable to ~~Generator~~ Supplier Derates

~~Generators~~ Suppliers that request and are granted a derate of their real-time Operating Capacity, but that are otherwise eligible to receive Day-Ahead Margin Assurance Payments may receive a payment up to a Capacity level consistent with their revised Emergency Upper Operating Limit or Normal Upper Operating Limit, whichever is applicable. If a ~~Generator's~~ Supplier's derated real-time Operating Capacity is lower than the sum of its Day-Ahead Energy Regulation Services and Operating Reserve schedules then when the ISO conducts the calculations described in Section 3.0 above, the DASen, DASeg and $DASres_p$ variables will be reduced by REDen, REDreg and $REDres_p$ respectively. REDen, REDreg and $REDres_p$ shall be calculated using the formulas below:

$REDtot_{iu} = \max(DASen_{hu} + DASreg_{hu} + \Sigma_p DASres_{hup} - RTUOL_{iu}, 0)$

$POTREDen_{iu} = \max(DASen_{hu} – RTSen_{iu}, 0)$

$POTREDreg_{iu} = \max(DASreg_{hu} – RTSreg_{iu}, 0)$

$POTREDres_{iup} = \max(DASres_{hup} – RTSres_{iup}, 0)$

$REDen_{iu} = ((POTREDen_{iu}/(POTREDen_{iu}+ POTREDreg_{iu}+ \Sigma_p POTREDres_{iup}))*REDtot_{iu}$

$REDreg_{iu} = ((POTREDreg_{iu}/(POTREDen_{iu}+ POTREDreg_{iu}+ \Sigma_p POTREDres_{iup}))*REDtot_{iu}$

$REDres_{iup} = ((POTREDres_{iup}/(POTREDen_{iu}+ POTREDreg_{iu}+ \Sigma_p POTREDres_{iup}))*REDtot_{iu}$

where:

$RTUOL_{iu}$ = The real-time Emergency Upper Operating Limit or Normal Upper Operating Limit whichever is applicable of Supplier u in interval i

$REDtot_{iu}$ = The total amount in MW that Day-Ahead schedules need to be reduced to account for the derate of Supplier u in interval i;

$REDen_{iu}$ = The amount in MW that the Day-Ahead Energy schedule is reduced for the purposes of calculating the Day-Ahead Margin Assurance Payment for Supplier u in interval i;

$REDreg_{iu}$ = The amount in MW that Supplier u's Day-Ahead Regulation Service schedule is reduced for the purposes of calculating the Day-Ahead Margin Assurance Payment in interval i;

$REDres_{iup}$ = The amount in MW that Supplier u's Day-Ahead Operating Reserve schedule for Operating Reserves product p is reduced for the purposes of calculating the Day-Ahead Margin Assurance Payment in interval i;

$POTREDen_{iu}$ = The potential amount in MW that Supplier u's Day-Ahead Energy schedule could be reduced for the purposes of calculating the Day-Ahead Margin Assurance Payment for Supplier u in interval i;

$POTREDreg_{iu}$ = The potential amount in MW that Supplier u's Day-Ahead Regulation Service Schedule could be reduced for the purposes of calculating the Day-Ahead Margin Assurance Payment for Supplier u in interval i;

$POTREDres_{iup}$ = The potential amount in MW that Supplier u's Day-Ahead Operating Reserve Schedule for Operating Reserve product p could be reduced for the purposes of calculating the Day-Ahead Margin Assurance Payment for Supplier in interval;

All other variables are as defined above.

Rate Schedule 3

Payments for Regulation Service

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

1.0 Obligations of the ISO and Suppliers

1.1 The ISO shall:

(a) Establish Regulation Service criteria and requirements in the ISO Procedures to ensure that ~~Generators~~ Suppliers follow changes in Load consistent with the Reliability Rules;

(b) Provide RTD Base Point Signals and AGC Base Point Signals to ~~Generators~~ Suppliers providing Regulation Service to direct their output;

(c) Establish criteria in the ISO Procedures that ~~Generators~~ Suppliers must meet to qualify, or re-qualify, to supply Regulation Service;

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

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

(f) Pay Suppliers for providing Regulation Service as described in Sections 4.0, 5.0, 6.0 and 7.0 of this Rate Schedule; and

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

1.2 Each Supplier shall:

(a) Register with the ISO the capacity its resources are qualified to bid in the Regulation Services market;

(b) Comply with Regulation Service criteria and requirements in the ISO Procedures;

(c~~a~~) Offer only ~~Generators~~ Resources that are; (i) ISO-Committed Flexible or Self-Committed Flexible, provided however that Demand Side Resources shall be offered as ISO-Committed Flexible; within the dispatchable portion of their operating range, and; (ii) able to respond to AGC Base Point Signals sent by the ISO pursuant to the ISO Procedures, to provide Regulation Service;

(d~~b~~) Not use, contract to provide, or otherwise commit Capability that is selected by the ISO to provide Regulation Service to provide Energy or Operating Reserves to any party other than the ISO;

(e~~c~~) Pay any charges imposed under this Rate Schedule including, if they are re-instituted the charges described in Section 8.0 of this Rate Schedule;

(~~d~~f) Ensure that all of its ~~Generators~~ Resources that are selected to provide Regulation Service comply with Base Point Signals issued by the ISO at all times pursuant to the ISO Procedures; and ensure that all of its ~~Generators~~ Resources that are selected to provide Regulation Service comply with all ISO Procedures that apply to providing Regulation Service.

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

(a) The ISO shall select Suppliers, in the Day-Ahead Market, to provide Regulation

Service for each hour in the following Dispatch Day, from those that have Bid to provide Regulation Service from ~~Generators~~ Resources that meet the qualification standards and criteria established in Section 1 of this Rate Schedule and in the ISO Procedures.

(b) Real-Time Market: The ISO shall establish a Real-Time Market for Regulation Service and will establish a real-time Regulation Service market clearing price in each interval. During any period when the ISO suspends ~~Generators'~~ Resources' obligation to follow the AGC Base Point Signals sent to Regulation Service providers, pursuant to Section 9.0 of this Rate Schedule, the Real-Time Market clearing price for Regulation Service shall automatically be set at zero, which shall be the price used for real-time balancing and settlement purposes. The ISO shall select Suppliers for Regulation Service from those that have Bid to provide Regulation Service from ~~Generators~~ Resources that meet the qualification standards and criteria established in the ISO Procedures.

(c) The ISO shall establish separate market clearing prices for Regulation Service in the Day-Ahead Market and the Real-Time Market under Sections 4.0, 5.0 and 7.0 of this Rate Schedule. The ISO shall also compute Regulation Revenue

Adjustment Payments and Regulation Revenue Adjustment Charges under Section 6.0 of this Rate Schedule.

2.1 Bidding Process (a) A Supplier may submit a Bid in the Day- Ahead Market or the Real-Time Market to provide Regulation Service from eligible ~~Generators~~ Resources, provided, however, that Bids submitted by Suppliers that are attempting to re-qualify to provide Regulation Service, after being disqualified pursuant to Section 3.0 of this Rate Schedule 3, may be limited by the ISO pursuant to ISO Procedures.

(b) Bids rejected by the ISO may be modified and resubmitted by the Supplier to the ISO in accordance with the terms of the ISO Tariff.

(c) Each Bid shall contain the following information: (i) the maximum amount of Capability (in MW) that the ~~Generator~~ Resource is willing to provide for Regulation Service; (ii) the ~~Generator's~~ Resource's regulation response rate (in MW/Minute) which must be sufficient to permit that ~~Generator~~ Resource to provide the offered amount of Regulation Service within an RTD interval ~~and which shall be the same as the response rate specified in the Energy Bid for that Generator~~; (iii) the Supplier's Availability Bid Price (in $/MW); and (iv) the physical location and name or designation of the ~~Generator~~ Resource.

3.0 Monitoring Regulation Service Performance and Performance Related Payment Adjustments

(a) ~~(a)~~ The ISO shall establish (i) ~~Generator~~ Resource performance measurement criteria; (ii) procedures to disqualify Suppliers whose ~~Generators~~ Resources consistently fail to meet those criteria; and (iii) procedures to re-qualify disqualified Suppliers, which may include a requirement to first demonstrate acceptable performance for a time.

(b) The ISO shall establish and implement a Performance Tracking System to monitor the performance of ~~Generators~~Suppliers that provide Regulation Service. The ISO shall develop performance indices, which may vary with Control Performance, as part of the ISO Procedures. The Performance Tracking System shall compute the difference between the Energy actually supplied and the Energy scheduled by the ISO for all ~~Generators~~ Suppliers serving Load within the NYCA as set forth in the ISO Procedures. The ISO shall use these values to reduce Regulation Service payments pursuant to Section 5.4 of this Rate Schedule.

(c) ~~Suppliers~~ Resources that consistently fail to perform adequately may be disqualified by the ISO, pursuant to ISO Procedures.

4.0 Regulation Service Settlements - Day-Ahead Market

4.1 Calculation of Day-Ahead Market Clearing Prices

The ISO shall calculate a Day-Ahead Market clearing price for Regulation Service each hour of the following day. The Day-Ahead Market clearing price for each hour shall equal the Day-Ahead Shadow Price of the ISO's Regulation Service constraint for that hour, which shall be established under the ISO Procedures. Day-Ahead Shadow Prices will be calculated by the ISO's SCUC. Each hourly Day-Ahead Shadow Price shall equal the marginal Bid cost of scheduling Resources to provide additional Regulation Service in that hour, including any impact on the Bid Production Cost of procuring Energy or Operating Reserves that would result from procuring an increment of Regulation Service in that hour,~~,~~ as calculated during the fifth SCUC pass described in Section I.B of Attachment B to this ISO Services Tariff, and Section I.B of Attachment J to the ISO OATT. As a result, the Shadow Price shall include the Day-Ahead Regulation Bid of the marginal Resource selected to provide Regulation Service (or in the applicable price on the Regulation Service Demand Curve during shortage conditions), plus any margins on the sale of Energy or Operating Reserves in the Day-Ahead Market that the Resource would forego if scheduling it to provide additional Regulation Service would lead to it being scheduled to provide less Energy or Operating Reserves. Shadow Prices shall also be consistent with the Regulation Service Demand Curves described in Section 7.0 of this Rate Schedule, which will ensure that Regulation Service is not scheduled by SCUC at a cost greater than the Regulation Service Demand Curve indicates should be paid. Each Supplier that is scheduled Day-Ahead to provide Regulation Service shall be paid the Day-Ahead Market clearing price in each hour, multiplied by the amount of Regulation Service that it is scheduled to provide in that hour.

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5.1A Calculation of Real-Time Market Clearing Prices for Regulation Service During EDRP/SCR Activations

During any interval in which the ISO is using scarcity pricing rule "A" or "B" to calculate LBMPs under section I.A.2.a or 2.b of Attachment B to this ISO Services Tariff, and Section I.A.2.a or 2.b of Attachment J to the ISO OATT, the real-time Regulation Service market clearing price may be recalculated in light of the Availability Bids of Suppliers and Lost Opportunity Costs of Generators scheduled to provide Regulation Service in real-time.

Specifically, when either scarcity pricing rule is applicable, the real-time Regulation Service clearing price shall be set to the higher of: (i) the highest total Availability Bid and Lost Opportunity Cost of any Regulation Service provider scheduled by RTD; and (ii) the market clearing price calculated under Section 5.1 of this Rate Schedule.

5.2 Real-Time Regulation Service Balancing Payments

Any deviation from a ~~Generator's~~ Supplier's Day-Ahead schedule to provide Regulation Service shall be settled pursuant to the following rules.

(a) When the ~~Generator's~~ Supplier's real-time Regulation Service schedule is less than its Day-Ahead Regulation Service schedule, the Generator shall pay a charge for the imbalance equal to the product of: (i) the Real-Time Market clearing price for Regulation Service; and (ii) the difference between the ~~Generator's~~ Supplier's Day-Ahead

Regulation Service schedule and its real-time Regulation Service schedule (subject to possible adjustments pursuant to Section 5.4 of this Rate Schedule.)

(b) When the ~~Generator's~~ Supplier's real-time Regulation Service schedule is greater than its Day-Ahead Regulation Service schedule, the ISO shall pay the ~~Generator~~ Supplier an amount to compensate it for the imbalance equal to the product of: (i) the Real-Time market clearing price for Regulation Service; and (ii) the difference between the ~~Generator's~~ Supplier's real-time Regulation Service schedule and its Day-Ahead Regulation Service schedule(subject to possible adjustments pursuant to Section 5.4 of this Rate Schedule.)

5.3 Other Real-Time Regulation Service Payments

As is provided in Article 4 and Attachment C of the Services Tariff, the ISO shall compensate each ISO-Committed Flexible Generator that provides Regulation Service if its Bid Production Cost to provide the Energy and Ancillary Services it is scheduled to supply in the Real-Time Market, including start-up costs, minimum Load costs, and Availability Bids, exceeds the revenues it receives from the sale of Energy and Ancillary Services.

No payments shall be made to any ~~Generator~~ Supplier providing Regulation Service in excess of the amount of Regulation Service scheduled by the ISO in the Real-Time Market, except to the extent that a ~~Generator~~ Supplier is directed to provide the excess amount by the ISO.

Finally, whenever a ~~Generator's~~ Supplier's real-time Regulation Service schedule is reduced by the ISO to a level lower than its Day-Ahead schedule for that product, the ~~Generator's~~ Supplier's Day-Ahead Margin shall be protected after accounting for any margin associated with other products that the ~~Generator~~ Supplier is scheduled to provide in real-time. The rules governing the calculation of these Day-Ahead Margin Assurance Payments are set forth in Attachment J to this ISO Services Tariff.

5.4 Performance-Based Adjustments to Regulation Service Payments

The amount paid to each ~~Generator~~ Supplier for providing Regulation Service in each RTD interval i shall be reduced to reflect the ~~Generator's~~ Supplier's performance pursuant to the following formula:

$$\text{Total Payment} = \Sigma_i(\text{Total Payment}_i * (s_i/3600))$$

Where:

$$\text{Total Payment}_i = (\text{DAMCPreg}_i \times \text{DARcap}_i) + ((\text{RTRcap}_i \times K_{PI}) - \text{DARcap}_i) \times \text{RTMCPreg}_i)$$

$DAMCPreg_i$ is the applicable market clearing price for Regulation Service (in $/MW), in the Day-Ahead Market, as established by the ISO pursuant to Section 4.1 of this Rate Schedule for the hour that includes RTD interval i;

DAR*cap*$_i$ is the Regulation Service Capability (in MW) offered by the ~~Generator~~ Resource and selected by the ISO in the Day-Ahead Market in the hour that includes RTD interval i;

$RTMCPreg_i$ is the applicable market clearing price for Regulation Service (in MW), in the Real-Time Market as established by the ISO under Section 5.1 of this Rate Schedule in RTD interval i;

$RTRcap_i$ is the Regulation Service Capability (in MW) offered by the ~~Generator~~ Resource and selected by the ISO in the Real-Time Market in RTD interval i;

s_i is the number of seconds in interval i; and

K_{pi} is a factor, with a value between 0.0 and 1.0 inclusive, derived from each ~~Generator's~~ Supplier's Regulation Service performance, as measured by the performance indices set forth in the ISO Procedures and determined pursuant to the following equation:~~.~~

$$K_{PI} = \frac{PI - PSF}{1 - PSF}$$

Where:

PI is the ~~Generator's~~ performance index of the Resource; and

PSF is the payment scaling factor, established pursuant to ISO Procedures. The PSF shall be set between 0 and the minimum performance index required for payment of Availability payments. The PSF is established to reflect the extent of ISO compliance with the standards established by NERC, NPCC or Good Utility Practice for Control Performance and System Security. The PSF is set initially at zero. Should the ISO's compliance with these measures deteriorate, in a manner that can be improved if regulation performance improves, the PSF will be increased. ~~Generators~~ Resources providing Regulation Service will be required to increase their performance index to obtain the same total Regulation Service payment as they received during periods of good ISO performance, as measured by these standards.

6.0 Energy Settlement Rules for Generators Providing Regulation Service

6.1 Energy Settlements

For any interval in which a Generator is providing Regulation

Service, it shall receive a settlement payment for Energy consistent with a real-time Energy injection equal to the lower of its actual generation or its AGC Base Point Signal. Demand Side Resources providing Regulation Service shall not receive a settlement payment for Energy.

6.2 Additional Payments/Charges When AGC Base Point Signals Exceed RTD Base Point Signals

For any interval in which a Generator that is providing Regulation Service receives an AGC Base Point Signal that is higher than its RTD Base Point Signal, it shall receive or pay a Regulation Revenue Adjustment Payment ("RRAP") or Regulation Revenue Adjustment Charge ("RRAC") calculated under the terms of this subsection. If the Energy Bid Price of such a Generator is higher than the LBMP at its location in that interval, the Generator shall receive a RRAP. Conversely, for any interval in which such a Generator's Energy Bid Price is lower than the LBMP at is location at that interval, the Generator shall be assessed a RRAC. RRAPs and RRACs shall be calculated using the following formula:

$$\text{Payment/Charge} = \int_{\text{RTD Base Point Signal}}^{\max(\text{RTD Base Point Signal},\min(\text{AGC Base Point Signal},\text{Actual Output}))} [\text{Bid} - \text{LBMP}] \quad \mathbf{* \ s/3600}$$

Where:

s is the number of seconds in the RTD interval;

If the result of the calculation is positive then the Generator shall receive a RRAP. If it is negative then the Generator shall be subject to a RRAC. For purposes of ~~this~~ applying this formula, whenever the Generator's actual Bid exceeds the applicable LBMP the "Bid" term shall be set at a level equal to the lesser of the Generator's actual Bid or its reference Bid plus $100/MWh.

6.3 ~~6.3~~ Additional Charges/Payments When AGC Base Point Signals Are Lower than RTD Base Point Signals

For any interval in which a Generator that is providing Regulation Service receives an AGC Base Point Signal that is lower than its RTD Base Point Signal, it shall receive or pay a RRAP or RRAC calculated under the terms of this subsection. If the Energy Bid Price of such a Generator is higher than the LBMP at its location in that interval, the Generator shall be assessed a RRAC. Conversely, for any interval in which such a Generator's Energy Bid Price is lower than the LBMP at its location in that interval, the Generator shall receive a RRAP. RRAPs and RRACs shall be calculated using the following formula:

$$\text{Payment/Charge} = \int_{\min(\text{RTD Base Point Signal},\max(\text{AGC Base Point Signal, Actual Output}))}^{\text{RTD Base Point Signal}} -[\text{Bid} - \text{LBMP}] \quad * \; s/3600$$

Where:

s is the number of seconds in the RTD interval;

If the result of the calculation is positive then the Generator shall receive a RRAP. If it is negative then the Generator shall be subject to a RRAC. For purposes of this formula, whenever the Generator's actual Bid is lower than the applicable LBMP the "Bid" term shall be set at a level equal to the higher of the Generator's actual Bid or its reference Bid minus $100/MWh.

6.4 Additional Charges / Payments to Demand Side Resources

Demand Side Resources providing Regulation Service shall not receive a RRAP, nor be subject to a RRAC.

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by eligible Suppliers located on Long Island. Each of these Operating Reserve requirements shall be defined consistent with the Reliability Rules and other applicable reliability standards. The ISO shall select Suppliers of Operating Reserves products to meet these requirements, including the locational Operating Reserves requirements, as part of its overall co-optimization process.

The ISO shall select Operating Reserves Suppliers that are properly located electrically so that all locational Operating Reserves requirements determined consistently with the requirements of Section 7.0 of this Rate Schedule are satisfied, and so that transmission Constraints resulting from either the commitment or dispatch of Generators do not limit the ISO's ability to deliver Energy to Loads in the case of a Contingency. The ISO will ensure that Suppliers that are compensated for using Capacity to provide one Operating Reserve product are not simultaneously compensated for providing another Operating Reserve product, or Regulation Service, using the same Capacity (consistent with the additive market clearing price calculation formulae in Sections 5.1 and 6.1 of this Rate Schedule).

1.2 Supplier Eligibility Criteria

The ISO shall enforce the following criteria, which define which types of ~~Generators or Demand Side Resources~~Suppliers are eligible to supply particular Operating Reserve products and shall require Suppliers to meet all criteria established by the ISO~~Reliability Rules~~. ~~In addition, the ISO shall establish technology, metering and testing procedures for the purpose of qualifying Demand Side Resources as eligible Suppliers. Each Generator and Demand Side Resource shall qualify its Resource with the ISO to bid in the Operating Reserves market pursuant to the following eligibility criteria.~~

a. Spinning Reserve: ~~Generators~~ Suppliers that are ISO Committed

Flexible or Self-Committed Flexible, are operating within the dispatchable portion of their operating range, are capable of responding to ISO instructions to change their output level within ten minutes~~, and are capable of producing Energy for at least thirty minutes~~ shall be eligible to supply Spinning Reserve.

b. **10-Minute Non-Synchronized Reserve**: Off-line Generators that are capable of starting, synchronizing, and increasing their output level within ten (10) minutes and that meet the criteria set forth in the ISO Procedures, and, ~~when the ISO's software can support their provision of this product,~~ Demand Side Resources that are capable of reducing their Energy usage within ten (10) minutes and that meet the criteria set forth in the ISO Procedures, shall be eligible~~, provided that they are capable of providing Energy for at least thirty minutes,~~ to supply 10-Minute Non-Synchronized Reserve.

c. **30-Minute Reserve**: (i) Suppliers~~Generators~~ that are ISO-Committed Flexible or Self-Committed Flexible and operating within the dispatchable portion of their operating range and Demand Side Resources, that are not Local Generators, that are capable of reducing their Energy usage within thirty (30) minutes and that meet the criteria set forth in the ISO Procedures, shall be eligible to supply synchronized 30-Minute Reserves; (ii) Off-line Generators that are capable of starting, synchronizing, and increasing their output level within thirty (30) minutes and that meet the criteria set forth in the ISO Procedures, and ~~when the ISO's software can support their provision of this product~~. ~~D~~Demand Side Resources that are capable of reducing their Energy usage within thirty (30) minutes and that meet the criteria set forth in the ISO Procedures, shall be eligible to supply non-synchronized 30-Minute Reserves.

2.0 General Day-Ahead Market Rules

2.1 Bidding and Bid Selection

Resources capable of providing Spinning Reserve, 10-Minute Non-Synchronized Reserve and/or 30-Minute Reserve in the Day-Ahead commitment may submit Availability Bids for each hour of the upcoming day. If a Supplier offers Resources that are capable, based on their indicated commitment status, of providing Operating Reserves but does not submit an Availability Bid, its Day-Ahead Bid will be rejected in its entirety. A Supplier may resubmit a complete Day-Ahead Bid, provided that the new bid is timely. ~~The same rules shall apply to Demand Side Resources capable of proving 10-Minute Non-Synchronized Reserve and/or non-synchronized 30-Minute Reserve when the ISO's software can support their provision of these products~~.

The ISO may schedule Suppliers that make themselves available to provide Operating Reserves up to the following maximum Operating Reserve levels: (i) for Spinning Reserves, the Resource's emergency response rate multiplied by ten; (ii) for 10-Minute Non-Synchronized Reserves, or for non-synchronized 30-Minute Reserves, the Resource's UOLN or UOLE, whichever is applicable at the relevant time (the Resource may offer one product or the other depending on the time required for it to start-up and synchronize to the grid); and (iii) for synchronized 30-Minute Reserves, the Resource's emergency response rate multiplied by twenty.

2.3 Real-Time Market Responsibilities of Suppliers Scheduled to Provide Operating Reserves in the Day-Ahead Market

Suppliers that are scheduled Day-Ahead to provide Operating Reserves shall either provide Operating Reserve, ~~or~~ Energy or~~, when the ISO's software can support Demand Side Resources' provision of non-synchronized Operating Reserves, reduce demand~~ Demand Reductions in real-time when scheduled by the ISO in all hours for which they have been selected to provide Operating Reserve and are physically capable of doing so. However, Suppliers that are scheduled Day-Ahead to provide Operating Reserves and have startup periods of two hours or less may advise the ISO no later than three hours prior to the first hour of their Day-Ahead schedule that they will not be available to provide Operating Reserves or Energy in real-time under normal conditions. Such Suppliers will be required to settle their Day-Ahead schedule at real-time prices pursuant to Section 6.2 of this Rate Schedule. The only restriction on Suppliers' ability to exercise this option is that all Suppliers with Day-Ahead Operating Reserves schedules must make the scheduled amount of Capacity available to the ISO for dispatch in the RTD if the ISO initiates a Supplemental Resource Evaluation.

3.0 General Real-Time Market Rules

3.1 Bid Selection

The ISO will automatically select Operating Reserves Suppliers in real-time from eligible Resources, ~~and when the ISO's software can support their provision of non-synchronized Operating Reserves, Demand Side Resources,~~ that submit Real-Time Bids pursuant to

Section 4.4 of, and Attachment D to, this ISO Services Tariff. ~~All~~Each Supplier~~s~~ will automatically be assigned a real-time Operating Reserves Availability bid of $0/MW for the quantity of Capacity that it makes available to the ISO in its Real-Time Bid. The ISO may schedule Suppliers that make themselves available to provide Operating Reserves up to the following maximum Operating Reserve levels: (i) for Spinning Reserves, the Resource's emergency response rate multiplied by ten; (ii) for 10-Minute Non-Synchronized Reserves, or for non-synchronized 30-Minute Reserves, the Resource's UOL_N or UOL_E, whichever is applicable at the relevant time (the Resource may offer one product or the other depending on the time required for it to start-up and synchronize to the grid); and (iii) for synchronized 30-Minute Reserves, the Resource's emergency response rate multiplied by twenty. However, the sum of the amount of Energy~~,~~ or~~, when the ISO's software can support Demand Side Resources' provision of non-synchronized Operating Reserves,~~ Demand Reduction, that each Resource is scheduled to provide, the amount of Regulation Service it is scheduled to provide, and the amount of each Operating Reserves product it is scheduled to provide shall not exceed its UOL_N or UOL_E, whichever is applicable.

Suppliers will thus be selected on the basis of their response rates, their applicable upper operating limits, and their Energy Bids (which will reflect their opportunity costs) through a co-optimized real-time commitment process that minimizes the total bid cost of Energy or Demand Reduction, Regulation

3.4 Activation of Operating Reserves

All Resources that are selected by the ISO to provide Operating Reserves shall respond to the ISO's directions to activate in real-time.

3.5 Performance Tracking and Supplier Disqualifications

When a Supplier committed ~~selected~~ to supply Operating Reserves is activated, the ISO shall measure and track its actual Energy production or its Demand Reduction against its expected performance in real-time. The ISO may disqualify Suppliers that consistently fail to provide Energy or Demand Reduction when called upon to do so in real-time from providing Operating Reserves in the future. If a Resource has been disqualified, the ISO shall require it to pass a re-qualification test before accepting any additional Bids to supply Operating Reserves from it. Disqualification and re-qualification criteria shall be set forth in the ISO Procedures.

3.6 Performance Index for Demand Side Resource Suppliers of Operating Reserves

The ISO shall produce a performance index for purposes of calculating the settlement for a Demand Side Resource providing Operating Reserves. The performance index shall take account of the actual Demand Reduction achieved by the Supplier of Operating Reserves following the ISO's instruction to convert Operating Reserves to Demand Reduction.

The performance index shall be a factor with a value between 0.0 and 1.0 inclusive. For each interval in which the ISO has not instructed the Demand Side Resource to covert its Operating Reserves to Demand Reduction, the Performance Index shall have a value of one. For each interval in which the ISO has instructed the Demand Side Resource to convert its Operating Reserves to Demand Reduction the Performance Index shall be calculated pursuant to the following formula:

Reserve PI = Min (UAGi ~~+ RETi)~~ / ADGi) +.1), 1

Where: Reserve PI = Reserve Performance Index
UAGi = Average actual demand reduction for interval i, represented as a positive generation value
ADGi = Average scheduled demand reduction for interval i, represented as a positive generation base point

4.0 Operating Reserves Settlements - General Rules

4.1 Establishing Locational Reserve Prices

Except as noted below, the ISO shall calculate separate Day-Ahead Market and Real-Time Market prices for each of the products

5.2 Other Day-Ahead Payments

As is provided in Section 4.10 and Attachment C of this ISO Services Tariff, the ISO shall compensate each ISO-Committed Flexible ~~Resource~~ Generator providing Operating Reserves if its Bid Production Cost to provide the Energy and Ancillary Services it is scheduled to supply in the Day-Ahead Market, including start-up costs, minimum Load costs, and Availability Bids, exceeds the revenues it receives from the sale of Energy and Ancillary Services. The ISO shall compensate each ISO-Committed Demand Side R~~r~~esource providing synchronized Operating Reserves if its Bid ~~Production Cost~~ to provide synchronized Operating Reserves it is scheduled to supply in the Day-Ahead Market, exceeds the revenues it receives from the sale of synchronized Operating Reserves in the Day-Ahead Market settlement.

6.0 Operating Reserve Settlements – Real-Time Market

6.1 Calculation of Real-Time Market Clearing Prices

The ISO shall calculate Real-Time Market clearing prices for each Operating Reserve product for each location in every interval. Except when the circumstances described below in Section 6.1A apply, each real-time market-clearing price shall equal the sum of the relevant real-time locational Shadow Prices for a given product, subject to the restriction described in Section 4.3 of this Rate Schedule.

The Real-Time Market clearing price for a particular Operating Reserve product for a particular location shall reflect the Shadow Prices associated with all of the ISO-defined Operating Reserve requirements, including locational requirements, that a particular Operating Reserves product from that location may be used to satisfy in a given interval. The ISO shall calculate the Real-Time Market clearing prices using the following formulae:

ensure that Operating Reserves are not scheduled by RTC at a cost greater than the relevant Operating Reserve Demand Curve indicates should be paid. If there is more Operating Reserve of the required quality than is needed to meet a particular locational Operating Reserve requirement then the Shadow Price for that Operating Reserve requirement constraint shall be zero.

Each Supplier that is scheduled in real-time to provide Operating Reserve shall be paid the applicable Real-Time Market clearing price, based on its location and the quality of Operating Reserve scheduled, multiplied by the amount of Operating Reserve that the Supplier is scheduled to provide in each interval that was not scheduled Day-Ahead.

6.1A Calculation of Real-Time Market Clearing Prices for Operating Reserves During EDRP/SCR Activations

A. During Intervals When Scarcity Pricing Rule "A" Applies

During any interval in which the ISO is using scarcity pricing rule "A" to calculate LBMPs under Section I.A.2.a of Attachment B to this ISO Services Tariff, and Section I.A.2.a of Attachment J to the ISO OATT, the real-time market clearing prices for some Operating Reserves products may be recalculated by in light of the Lost Opportunity Costs of Resources that are scheduled to provide Spinning Reserves and synchronized 30-Minute Reserves in the manner described below. The ISO shall also consider the Lost Opportunity Costs of Resources providing lower quality Operating Reserves to ensure that the requirements of Section 4.3 of this Rate Schedule are not violated. Specifically:

The Eastern 10-Minute Non-Synchronized Reserve market clearing price shall be the higher of: (i) the highest Lost Opportunity Cost of any provider of Eastern synchronized 30-Minute Reserve that is scheduled by RTD and is not located on Long Island; and (ii) the original market clearing price calculated under Section 6.1 above.

The Eastern 30-Minute Reserve market clearing price shall be the higher of: (i) the highest Lost Opportunity Cost of any provider of Eastern synchronized 30-Minute Reserve that is scheduled by RTD and is not located on Long Island; and (ii) the original market clearing price calculated under Section 6.1 above.

Real-Time Market clearing prices for Western Reserve shall not be affected under scarcity pricing rule "B".

6.2 Operating Reserve Balancing Payments

Any deviation in performance from a Supplier's Day-Ahead schedule to provide Operating Reserves, including deviations that result from schedule modifications made by the ISO, shall be settled pursuant to the following rules.

(a) When the Supplier's real-time Operating Reserves schedule is less than its ~~assigned~~ Day-Ahead Operating Reserves schedule, the Supplier shall pay a charge for the imbalance equal to the product of: (i) the Real-Time Market clearing price for the relevant Operating Reserves Product in the relevant location; and (ii) the difference between the Supplier's Day-Ahead and real-time Operating Reserves schedules.

(b) When the Supplier's real-time Operating Reserves schedule is greater than its ~~assigned~~ Day-Ahead Operating Reserves schedule, the ISO shall pay the Supplier an amount to compensate it for the imbalance equal to the product of: (i) the Real-Time Market clearing price for the relevant Operating Reserve product in the relevant location; and (ii) the difference between the Supplier's Day-Ahead and real-time Operating Reserves schedules.

6.3. Other Real-Time Payments

The ISO shall pay Generators that are selected to provide Operating Reserves, but are directed to convert to Energy production in real-time, the applicable Real-Time LBMP for all Energy they are directed to produce in excess of their Day-Ahead schedule.

As is provided in Section 4.10 and Attachment C of this ISO Services Tariff, the ISO shall compensate each eligible Generator ~~Supplier~~ providing Operating Reserves if its Bid Production Cost to provide the Energy and Ancillary Services it is scheduled to supply in the Real-Time Market, including Minimum Generation Bid and Start-Up Bid costs exceeds the revenues it receives from the sale of Energy and Ancillary Services. Any Generator~~Supplier~~ that provides Energy during a large event reserve pickup or a maximum generation event, as described in Sections 4.4.4(A) (1) and (2) of this ISO Services Tariff~~-~~ shall be eligible for a Bid Production Cost guarantee payment calculated, under Attachment C, solely for the duration of the large event reserve pickup or maximum generation pickup. Such payments shall be excluded from the ISO's calculation of real-time Bid Production Cost guarantee payments otherwise payable to Suppliers on that Dispatch Day.

Finally, whenever a ~~Resource's~~ Supplier's real-time Operating Reserves schedule is reduced by the ISO to a level lower than its Day-Ahead schedule for that product, the ~~Resource's~~ Supplier's Day-Ahead Margin shall be protected after accounting for any margin associated with other products that the Resource is scheduled to provide in real-time for that time period. The rules governing the calculation of these Day-Ahead Margin Assurance Payments are set forth in Attachment J to this ISO Services Tariff.

7.0 Operating Reserve Demand Curves

The ISO shall establish nine Operating Reserve Demand Curves, one for each Operating Reserves requirement. Specifically, there shall be a demand curve for: (i) Total Spinning Reserves; (ii) Eastern or Long Island Spinning Reserves; (iii) Long Island Spinning Reserves; (iv) Total 10-Minute Non-Synchronized Reserves; (v) Eastern or Long Island 10-Minute Non-Synchronized Reserves; (vi) Long Island 10-Minute Non-Synchronized Reserves; (vii) Total 30-Minute Reserves; (viii) Eastern or Long Island 30-Minute Reserves; and (ix) Long Island 30-Minute Reserves. Each Operating Reserve Demand Curve will apply to both the Day-Ahead Market and the Real-Time Market for the relevant product and location.

The market clearing pricing for Operating Reserves shall be calculated pursuant to Sections 5.1 and 6.1 of this Rate Schedule and in a manner consistent with the demand curves established in this Section so that Operating Reserves are not purchased by SCUC or RTC at a cost higher than the relevant demand curve indicates should be paid.