15 ISO Market Administration and Control Area Service Tariff Rate Schedules

DRAFT – FOR DISCUSSION PURPOSES ONLY
For discussion at April 2019 Management Committee Meeting

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

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

15.2 Rate Schedule 2 - Payments for Supplying Voltage Support Service

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

Suppliers provide Voltage Support Service from eligible providers which are Generators with an Automatic Voltage Regulator ("Generators," for the purpose of this Rate Schedule 2), synchronous condensers, and Qualified Non-Generator Voltage Support Resources. Aggregations are not eligible to provide Voltage Support Service.

Qualified Suppliers of Voltage Support Service shall be referred to as such or as Voltage Support Resources in this Rate Schedule. An RMR Generator operating under an RMR Agreement that provided Voltage Support Service at any time during the most recent twelve (12) months that it participated in the ISO Administered Markets must provide Voltage Support Service during the term of its RMR Agreement, unless it demonstrates to the ISO's satisfaction that it is no longer capable of providing the service. An Interim Service Provider that provided Voltage Support Service during the most recent twelve (12) months that it participated in the ISO Administered Markets must continue to provide Voltage Support Service, unless it demonstrates to the ISO's satisfaction that it is no longer capable of providing the service. The rate provided in this Rate Schedule shall be used to calculate payments to eligible Suppliers providing Voltage Support Service as applied on a technology-specific basis. The ISO shall calculate payments on an annual basis, and make payments monthly.

15.2.1 Responsibilities

The ISO shall coordinate the Voltage Support Service provided by Suppliers that qualify to provide such services as described in Section 15.2.1.1 of this Rate Schedule 2. The ISO shall also establish methods and procedures for Reactive Power (MVAr) capability testing.

15.2.1.1 Suppliers

To qualify for payments, Suppliers of Voltage Support Service shall provide a Generator that has an AVR, or a Qualified Non-Generator Voltage Support Resource with, other than the Cross Sound Scheduled Line, an AVR, or a synchronous condenser, each of which must be electrically located within the NYCA. All Suppliers of Voltage Support Service must successfully perform Reactive Power (MVAr) capability testing in accordance with the ISO Procedures and prevailing industry standards. The ISO may direct Qualified Suppliers of Voltage Support Service to operate their Voltage Support resources within these demonstrated reactive capability limits. Qualified Suppliers of Voltage Support Service will test their Voltage Support Resources and provide these services in accordance with ISO Procedures.

Voltage Support Service includes the ability to produce or absorb Reactive Power within the Voltage Support Resource's tested reactive capability, and the ability to maintain a specific voltage level under both steady-state and post-contingency operating conditions subject to the limitations of the Voltage Support Resource's stated reactive capability. The requirement for a Voltage Support Resource to absorb Reactive Power may be set aside by the ISO with input from the Transmission Owner in whose Transmission District the Voltage Support Resource is located, which input may include, at the Transmission Owner's option, an executive level review. To grant an exemption from the requirement that the Voltage Support Resource be able to absorb Reactive Power, the ISO shall have determined that: 1) the Voltage Support Resource is unable, due to transmission system configuration, to absorb Reactive Power; 2) the ability of the Voltage Support Resource to produce Reactive Power is needed for system reliability; and 3) for purposes of system reliability the Voltage Support Resource does not need to have the ability to absorb Reactive Power.

An RMR Generator that is required to provide Voltage Support Service must timely perform the annual testing applicable to all Suppliers of Voltage Support Service described in this Section 15.2.1 and in ISO Procedures so that it remains continuously eligible to provide Voltage Support Service during the term of its RMR Agreement. If such an RMR Generator did not timely perform all of the annual testing required for it to provide Voltage Support Service prior to the start of the term of its RMR Agreement, then the ISO shall permit the RMR Generator to perform Reactive Power (MVAr) capability testing in accordance with the ISO Procedures upon entering the RMR Agreement and shall permit the RMR Generator to be a Qualified Supplier of Voltage Support Service. An Interim Service Provider must timely perform the annual testing applicable to all Suppliers of Voltage Support Service described in this Section 15.2.1 and in ISO Procedures so that it remains continuously eligible to provide Voltage Support Service. If such an Interim Service Provider did not timely perform all of the annual testing required for it to provide Voltage Support Service, then the ISO shall permit the Interim Service Provider to perform Reactive Power (MVAr) capability testing in accordance with the ISO Procedures promptly upon becoming an Interim Service Provider and shall permit the Interim Service Provider to be a Qualified Supplier of Voltage Support Service.

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15.2.2 Payments

Each month, Suppliers whose Generator(s) meet the requirements to supply Installed Capacity, as described in Article 5 of the ISO Services Tariff, and are under contract to supply Installed Capacity, shall receive one-twelfth (1/12th) of the annual payment calculated under Section 15.2.2.1 of this Rate Schedule for Voltage Support Service.

Each month, Suppliers whose Generators are not under contract to supply Installed Capacity, Suppliers with synchronous condensers, and, except as noted in the following paragraph, Qualified Non-Generator Voltage Support Resources shall receive one-twelfth (1/12th) of the annual payment calculated under Section 15.2.2.1 of this Rate Schedule , pro-rated by the number of hours that the Generator, synchronous condenser, or Qualified Non-Generator Voltage Support Resource operated in that month, as recorded by the ISO.

Each month, the Cross-Sound Scheduled Line shall receive one-twelfth (1/12th) of the annual payment calculated under Section 15.2.2.1 of this Rate Schedule, pro-rated by the number of hours that it is energized in that month, as recorded by the ISO.

15.2.2.1 Annual Payment for Voltage Support Service

For purposes of the calculation set forth in Section 15.2.2 of this Rate Schedule, the annual payment to Suppliers qualified and eligible to provide Voltage Support Service shall equal the product of the VSS Compensation Rate and the sum of the lagging and the absolute value of the leading MVAr capacity of the resource, as evidenced by tests conducted pursuant to ISO Procedures. The VSS Compensation Rate of $2,592/MVAr, as determined in 2014, shall be adjusted annually by the annual average Consumer Price Index of the previous year.

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15.2.2.2 Lost Opportunity Costs

A Supplier of Voltage Support Service from a Generator that is being dispatched by the ISO shall also receive a payment for Lost Opportunity Costs ("LOC") when the ISO directs the Generator to reduce its real power (MW) output below its Economic Operating Point in order to allow the Generator to produce or absorb more Reactive Power (MVAr), unless the Supplier is already receiving a Day-Ahead Margin Assurance Payment for that reduction under Attachment J to this ISO Services Tariff. The Lost Opportunity Cost payment shall be calculated as the maximum of zero or the difference between: (i) the product of: (a) the appropriate MW of output reduction and (b) the Real-Time LBMP at the Generator bus; and (ii) the Generator's Energy Bid for the reduced output of the Generator multiplied by the time duration of reduction in hours or fractions thereof.

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

$$LOC_i = max\left(\left(LBMP_{RT,i} * \left(EOP_i - max(AEI_i, RTS_i, DAS_i)\right) - \int_{max(AEI_i,RTS_i,DAS_i)}^{EOP_i} Bid\right), 0\right) * \frac{S_i}{3600}$$

Where:

LOC_i = Lost Opportunity Cost for interval *i*

$LBMP_{RT,i}$ = Real-time LBMP for interval *i*

EOP_i = The Generator's Economic Operating Point for interval *i*

AEI_i = The Generator's Actual Energy Injection for the interval *i*

RTS_i = The Generator's Real-Time Energy Schedule for interval *i*

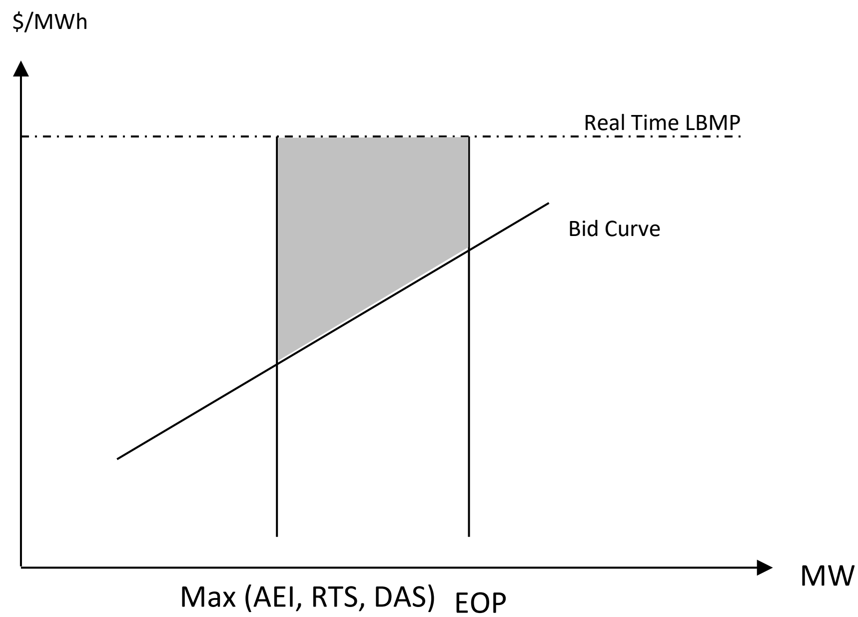
DAS_i = The Generator's Day-Ahead Schedule for the hour containing *i*

Bid_i = Generator's Bid curve in effect for interval *i*

$S_i/3600$ = The length of interval *i*, containing $S_i^{seconds}$ in units of hours

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

Figure 2.0(b) - Incremental Bid Curve Used to Calculate LOC



15.2.2.3 Other Payments to Synchronous Condensers and Qualified Non-Generator Voltage Support Resources

If a synchronous condenser or Qualified Non-Generator Voltage Support Resource energizes in order to provide Voltage Support Service in response to a request from the ISO, the ISO shall compensate the facility for the cost of Energy it consumes to energize converters and other equipment necessary to provide that Voltage Support Service.

15.2.3 Failure to Perform by Suppliers

A Generator, synchronous condenser, or a Qualified Non-Generator Voltage Support Resource will have failed to provide voltage support if it:

15.2.3.1 when operating at real-power levels consistent with test conditions, fails within ten minutes to be within 5% (+/-) of the requested Reactive Power (MVAr) level of production or absorption as requested by the ISO or applicable Transmission Owner unless it was prevented from doing so by transmission system conditions and except when the Voltage Support Resource is requested not to produce or absorb Reactive Power in which case that Voltage Support Resource fails to provide Voltage Support if the absolute value of its level of Reactive Power production or absorption within ten minutes is greater than 5% multiplied by the sum of the absolute values of (a) that Voltage Support Resource's maximum reactive power production level under test conditions and (b) that Voltage Support Resource's maximum reactive power absorption level under test conditions;

15.2.3.2 when operating at real-power levels consistent with test conditions, fails within ten minutes to be at 95% or greater of the Voltage Support Resource's demonstrated Reactive Power capability (tested pursuant to ISO Procedures) in the appropriate lead or lag direction when requested to go to maximum lead or lag reactive capability by the ISO or applicable Transmission Owner unless it was prevented from doing so by transmission system conditions;

15.2.3.3 fails to provide Voltage Support Service in a Contingency, as defined by ISO Procedures;

15.2.3.4 fails to maintain its automatic voltage regulator (as appropriate) in service and in automatic voltage control mode, or fails to commence timely repairs to the automatic voltage regulator.

Suppliers of Voltage Support Service that fail to comply with the ISO Procedures will be assessed charges by the ISO in the manner described in Sections 15.2.4, 15.2.5, and 15.2.6 below.

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15.2.4 Failure to Respond to ISO's Request for Steady-State Voltage Control

Failure: If a Voltage Support Resource fails to comply with the ISO’s request for steady-state voltage control, the ISO shall withhold Voltage Support Service payments from the non-complying Supplier equivalent to the VSS Failure to Perform Penalty for that specific Generator, synchronous condenser, or Qualified Non-Generator Voltage Support Resource for that month. The Supplier shall also be liable for any additional cost in procuring replacement Voltage Support Service including LOC incurred by the ISO as a direct result of the Supplier’s non-performance.

The formula below describes the monthly VSS Failure to Perform Penalty (VFP)

$$VFP = (VSS\ payment\ for\ the\ month) * (F/R)$$

Where:

F = number of failures in the month

R = number of times the Voltage Support Resource was called upon for Voltage Support in the month

Repeated Failures: In addition to the charges for failure, the non-complying Supplier will also be subject to the charges described in this paragraph. If a Supplier’s Voltage Support Resource fails to comply with fifty percent (50%) or more of the ISO's requests for two consecutive months, then the non-complying Supplier will no longer be eligible for Voltage Support Service payments for service provided by that Voltage Support Resource. The ISO may reinstate payments once the Supplier complies with the following conditions to the ISO's satisfaction:

15.2.4.1 the Supplier's Voltage Support Resource must successfully perform a Reactive Power (MVAr) capability test, and

15.2.4.2 the Supplier's Voltage Support Resource must provide Voltage Support Service for thirty (30) consecutive days without any compliance failures. No payments for Voltage Support Service or LOC will be made to the Supplier on account of Voltage Support Service from such Voltage Support Resource during this period.

15.2.5 Failure to Provide Voltage Support Service When a Contingency Occurs on the NYS Power System

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

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

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

15.2.5.1 the Supplier's Voltage Support Resource shall successfully perform a Reactive Power (MVAr) capability test, and

15.2.5.2 the Supplier's Generator, synchronous condenser, or Qualified Non-Generator Voltage Support Resource shall provide Voltage Support Service for thirty (30) consecutive days without any compliance failures. No payments for Voltage Support Service, or LOC shall be made to the Supplier on account of Voltage Support Service from such Generator, synchronous condenser, or Qualified Non-Generator Voltage Support Resource during this period.

15.2.6 Failure to Maintain an Automatic Voltage Regulator or Commence Timely Repairs

If a Supplier's Voltage Support Resource, other than the Cross Sound Scheduled Line, fails to maintain its automatic voltage regulator and fails to notify the ISO, in accordance with ISO procedures, of an outage lasting more than thirty (30) days the Voltage Support Resource will be disqualified as a supplier of Voltage Support Service.

The Supplier will not receive Voltage Support Service payments for the disqualified Voltage Support Resource until the Supplier complies with the following conditions:

(1) the Supplier provides documentation to the NYISO of the completion of the repairs;

(2) the Supplier's Voltage Support Resource successfully performs a Reactive Power (MVAr) capability test, and;

(3) the Supplier's Voltage Support Resource provides Voltage Support Service for thirty (30) consecutive days without any compliance failures. No payments for Voltage Support Service or LOC on account of Voltage Support Service from such Generator or Qualified Non-Generator Voltage Support Resource shall be made to the Supplier during this period.

If, in accordance with ISO procedures, a Qualified Supplier of Voltage Support Service notifies the ISO within thirty days of an automatic voltage regulator outage that lasts longer than thirty days, but the Supplier fails to commence timely and appropriate repairs, the Voltage Support Resource will remain in the VSS program and will receive one half its full monthly VSS payment. The Voltage Support Resource will begin receiving full monthly VSS payment when its AVR returns to full functionality. The Voltage Support Resource will not be eligible for VSS payment in the next compensation year if it fails to repair its AVR and perform an acceptable test in accordance with ISO procedures.

15.2.7 Consistence with Cross-Sound Scheduled Line Protocols

Nothing in this Rate Schedule shall be construed to change existing protocols between the ISO and ISO New England, Inc. regarding the operation of the Cross-Sound Scheduled Line.

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15.3 Rate Schedule 3 - Payments for Regulation Service

This Rate Schedule applies to Suppliers that provide Regulation Service to the ISO. ~~A~~ The following Resources are not eligible to provide Regulation Service: (1) Behind-the-Meter Net Generation Resources that ~~is~~ are comprised of more than one generating unit and that ~~is~~ are dispatched as a single aggregate unit, ~~and~~(2) Aggregations that are comprised of one or more generating units (unless each of those generating units use inverter-based energy storage technology), and (3) Aggregations of Demand Side Resources where at least one Demand Side Resource facilitates its Demand Reduction by utilizing a Local Generator (unless ~~that~~each Local Generator uses inverter-based energy storage technology)~~, are not qualified to provide Regulation Service to the ISO~~. Transmission Customers will purchase Regulation Service from the ISO under the ISO OATT.

15.3.1 Obligations of the ISO and Suppliers

15.3.1.1 The ISO shall:

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

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

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

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

(e) Select Suppliers to provide Regulation Service in the Day-Ahead Market and Real-Time Market and establish Regulation Service schedules, in MWs of Regulation Capacity, for each scheduled Regulation Supplier in the Day-Ahead and Real-Time Markets, as described in Section 15.3.2 of this Rate Schedule;

(f) Pay Suppliers for providing Regulation Service as described in this Rate Schedule;

(g) Monitor Suppliers' performance to ensure that they provide Regulation Service as required, as described in Section 15.3.3 of this Rate Schedule; and

(h) Take into account the speed and accuracy of regulation resources in determining reserve requirements for Regulation Service.

15.3.1.2 Each Supplier shall:

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

(b) Provide the ISO with the Resource's Regulation Capacity Response Rate and the Resource's Regulation Movement Response Rate;

(c) Offer only 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) Not use, contract to provide, or otherwise commit Regulation Capacity that is selected by the ISO to provide Regulation Service to provide Energy or Operating Reserves to ~~any party~~a Balancing Authority other than the ISO;

(e) Pay any charges imposed under this Rate Schedule;

(f) Ensure that all of its 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 Resources that are selected to provide Regulation Service comply with all criteria and ISO Procedures that apply to providing Regulation Service.

15.3.2 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 and in the Real-Time Market to provide Regulation Service for each interval in the Dispatch Day, from those that have Bid to provide Regulation Service from Resources and that meet the qualification standards and criteria established in Section 15.3.1 of this Rate Schedule and in the ISO Procedures.

(b) In order to schedule Suppliers in the Day-Ahead Market to provide Regulation Service for each hour in the following Dispatch Day, the ISO shall use, as each Supplier's Regulation Service Bid price, the sum of: a) the Supplier's Day-Ahead Regulation Capacity Bid Price and b) the product of the Supplier's Day-Ahead

Regulation Movement Bid Price and the applicable Regulation Movement Multiplier.

(c) In order to schedule Suppliers in the Real-Time Market to provide Regulation Service for each interval in the Dispatch Day the ISO shall use, as each Supplier's Regulation Service Bid price, the sum of: a) the Supplier's Real-Time Regulation Capacity Bid Price and b) the product of the Supplier's Real-Time Regulation Movement Bid Price and the applicable Regulation Movement Multiplier.

(d) The ISO shall establish separate Regulation Capacity Market Prices in the Day-Ahead Market and the Real-Time Market under Sections 15.3.4, 15.3.5 and 15.3.7 of this Rate Schedule and shall establish a Real-Time Regulation Movement Market Price under Section 15.3.5.1 of this Rate Schedule. The ISO shall also compute Regulation Revenue Adjustment Payments and Regulation Revenue Adjustment Charges under Section 15.3.6 of this Rate Schedule.

15.3.2.1 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 Resources, provided, however, that Bids submitted by Suppliers that are attempting to re-qualify to provide Regulation Service, after being disqualified pursuant to Section 15.3.3 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 Resource is willing to provide as Regulation

Capacity; (ii) the Supplier's Bid Price (in $/MW) for Regulation Capacity; and (iii) the Suppliers Bid Price (in $/MW) for Regulation Movement~~; and (iv) the physical location and name or designation of the Resource~~.

(d) Regulation Service Offers from Limited Energy Storage Resources: The ISO may reduce the real-time Regulation Capacity offer (in MWs) from a Limited Energy Storage Resource ~~(~~or an Aggregation of Limited Energy Storage Resources ~~thereof)~~ to account for the Energy storage capacity of such Resource.

(e) Regulation Service Offers from Energy Storage Resources: The ISO may reduce the real-time Regulation Capacity (in MW) from an Energy Storage Resource ~~(~~or an Aggregation of Energy Storage Resources ~~thereof)~~ to account for the Energy Level of such Resource.

15.3.3 Monitoring Regulation Service Performance and Performance Related Payment Adjustments

(a) The ISO shall establish (i) Resource performance measurement criteria; (ii) procedures to disqualify Suppliers whose 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 Suppliers that provide Regulation Service. The ISO shall develop performance indices, which may vary with Control Performance, as part of the ISO Procedures. The ISO shall use the values provided by the Performance Tracking System to adjust settlements for real-time Regulation Movement pursuant to Section 15.3.5.4.1 and to compute a performance charge to apply to real-time Regulation Service providers pursuant to Section 15.3.5.4.2 of this Rate Schedule.

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

15.3.4 Regulation Service Settlements - Day-Ahead Market

15.3.4.1 Calculation of Day-Ahead Market Prices

The ISO shall calculate a Day-Ahead Regulation Capacity Market Price for each hour of the following day. The Day-Ahead Regulation Capacity Market 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, minus the product of i) the Day-Ahead Regulation Movement Bid Price of the marginal Resource selected to provide Regulation Service; and ii) the applicable Regulation Movement Multiplier. 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 17.1.3 of Attachment B to this ISO Services Tariff. As a result, the Shadow Price shall include the Day-Ahead Regulation Service Bids of the marginal Resource selected to provide Regulation Service, plus any margins on the sale (or purchase by a Withdrawal-Eligible Generator) of Energy or the sale of 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 (or for a Withdrawal-Eligible Generator to withdraw) less Energy or to provide less Operating Reserves (or the applicable price on the Regulation

Service Demand Curve during shortage conditions). Shadow Prices consistent with the Regulation Service Demand Curves described in Section 15.3.7 of this Rate Schedule will ensure that Regulation Service is not scheduled by SCUC at a cost greater than the Regulation Service Demand Curve.

Each Supplier that is scheduled Day-Ahead to provide Regulation Service shall be paid the Day-Ahead Regulation Capacity Market Price in each hour, multiplied by the amount of Regulation Capacity that it is scheduled Day-Ahead to provide in that hour.

15.3.4.2 Other Day-Ahead Payments

A Supplier that bids on behalf of a Generator or Aggregation that provides Regulation Service may be eligible for a Day-Ahead Bid Production Cost guarantee payment pursuant to Section 4.6.6 and Attachment C of this ISO Services Tariff.

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

15.3.5 Regulation Service Settlements - Real-Time Market

15.3.5.1 Calculation of Real-Time Market Prices

The ISO shall calculate a Real-Time Regulation Capacity Market Price and a Real-Time Regulation Movement Market Price for every RTD interval, except as noted in Section 15.3.8 of this Rate Schedule. The Real-Time Regulation Capacity Market Price for each interval shall equal the real-time Shadow Price for the ISO's Regulation Service constraint for that RTD interval, which shall be established under the ISO Procedures, minus the product of: i) the real-time Regulation Movement Bid of the marginal Resource selected to provide Real-Time

Regulation Service; and ii) the applicable Regulation Movement Multiplier. Real-time Shadow Prices will be calculated by the ISO's RTD. Each Real-Time Shadow Price in each RTD interval shall equal the marginal Bid cost of scheduling Resources to provide additional Regulation Service in that interval, 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 interval. As a result, the Shadow Price shall include the Real-Time Regulation Service Bids of the marginal Resource selected to provide Regulation Service, plus any margins on the sale (or for Withdrawal-Eligible Generators, the purchase) of Energy or the sale of Operating Reserves in the Real-Time Market that Resource would forego if scheduling it to provide additional Regulation Service would lead to it being scheduled to provide or withdraw less Energy or to provide less Operating Reserves (or the applicable price on the Regulation Service Demand Curve during shortage conditions). Shadow Prices consistent with the Regulation Service Demand Curves described in Section 15.3.7 of this Rate Schedule will ensure that Regulation Service is not scheduled at a cost greater than the Demand Curve indicates.

During any period when the ISO sets Resources' Regulation Service Schedules to zero, pursuant to Section 15.3.8 of this Rate Schedule, the Real-Time Regulation Capacity Market Price and the Real-Time Regulation Movement Market Price shall automatically be set to zero, which shall be the price used for real-time balancing and settlement purposes.

The ISO shall calculate a Real-Time Regulation Movement Market Price for every RTD interval. The Real-Time Regulation Movement Market Price shall be the Regulation Movement Bid of the marginal Resource selected to provide Regulation Service in that interval.

15.3.5.2 Real-Time Regulation Capacity Balancing Payments, Regulation Movement Payments and Performance Charges

Any deviation from a Supplier's Day-Ahead schedule to provide Regulation Service shall be settled pursuant to the following rules. In addition, Suppliers scheduled to provide Regulation Service in real-time shall be settled pursuant to the following rules.

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

(b) When the Supplier's real-time Regulation Capacity schedule is greater than its Day-Ahead Regulation Capacity schedule, the ISO shall pay the Supplier an amount to compensate it for the imbalance equal to the product of: (i) the Real-Time Regulation Capacity Market Price; and (ii) the difference between the Supplier's real-time Regulation Capacity schedule and its Day-Ahead Regulation Capacity schedule.

(c) The ISO shall pay Suppliers with real-time Regulation Capacity schedules a real-time payment for Regulation Movement provided in each interval. The payment amount shall equal the product of: (a) the Real-Time Regulation Movement Market Price in that interval; (b) the Regulation Movement instructed during the interval, and (c) the performance factor calculated for that Regulation Service provider in that interval pursuant to Section 15.3.5.4.1.

(d) The ISO shall assess a performance charge, pursuant to Section 15.3.5.4.2 to all Suppliers of Regulation Service with real-time Regulation Service schedules.

(e) No payments shall be made to any 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 Supplier is directed to provide the excess amount by the ISO.

15.3.5.3 Other Real-Time Regulation Service Payments

A Supplier that bids on behalf of a Regulation Service provider may be eligible for a real-time Bid Production Cost guarantee payment pursuant to Section 4.6.6 and Attachment C of this ISO Services Tariff.

A Supplier that bids on behalf of a Regulation Service provider may also be eligible for a Day-Ahead Margin Assurance Payment pursuant to Section 4.6.5 and Attachment J of this ISO Services Tariff.

15.3.5.4 Performance-Based Adjustment to Payments for Regulation Service Providers and Performance Based Charges

15.3.5.4.1 Performance-Based Adjustment to Payments for Regulation Service Suppliers

The amount paid to each Supplier for providing Regulation Movement in each RTD interval, pursuant to Section 15.3.5.2 shall be reduced to reflect the Supplier's performance using a performance factor developed pursuant to the following equation:

$$K_{PIi} = (PI_i - PSF)/(1 - PSF)$$

Where:

K_{PIi} = the performance factor derived from the Regulation Service Performance index for the Resource for interval *i*;

PI_i = the performance index of the Resource for interval *i*, with a value between 0.0 and 1.0 inclusive, derived from each Supplier's Regulation Service performance, as measured by the performance indices set forth in the ISO Procedures; and

PSF = the payment scaling factor, established pursuant to ISO Procedures. The PSF shall be set between 0 and the minimum performance index required for payment for Regulation Service.

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. 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.

15.3.5.4.2 Performance-Based Charge to Suppliers of Regulation Service

In addition, each Supplier that is scheduled in real-time to provide Regulation Service shall be assessed a performance charge for interval *i* in accordance with the following formula.

$$
\begin{aligned}
&Performance\ Charge_i \\
&\quad = \Big(\big((1 - K_{PIi}) * RTRinccap_i * \text{-}1.1 * RTMPreg_i\big) \\
&\quad + \big(((1 - K_{PIi}) * (RTRcap_i - RTRinccap_i) * \text{-}1.1\big) * Max\big(DAMPreg_{,} RTMPreg_i\big)\big)\Big) * (S_i/3600)
\end{aligned}
$$

$DAMPreg_i$ = is the applicable Regulation Capacity Market Price (in \$/MW), in the Day-Ahead Market, as established by the ISO pursuant to Section 15.3.4.1 of this Rate Schedule for the hour that includes RTD interval *i*;

$RTMPreg_i$ = is the applicable Regulation Capacity Market Price (in \$/MW), in the Real-Time Market as established by the ISO under Section 15.3.5.1 of this Rate Schedule in RTD interval *i*;

$RTRcap_i$ = is the Regulation Capacity (in MW) offered by the Resource and selected by the ISO in the Real-Time Market in RTD interval i;

$RTRinccap_i$ = is the incremental Regulation Capacity (in MW) offered by the Resource and selected by the ISO in the Real-Time Market in the RTD interval i which is in excess of Regulation Capacity offered and selected by the ISO in the Day-Ahead Market for the hour that includes interval i;

S_i = is the number of seconds in interval i; and

K_{PIi} = is the performance factor for the Resource for interval i as defined in Section 15.3.5.4.1.

15.3.6 Energy Settlement Rules for ~~Generators~~ Suppliers Providing Regulation Service

15.3.6.1 Energy Settlements

A. For any interval in which a Generator or Aggregation that is not a Limited Energy Storage Resource ~~(~~or an Aggregation ~~there~~of Limited Energy Storage Resources~~)~~ 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~~ the actual ~~generation supply~~Energy it provides or its AGC Base Point Signal.

B. Demand Reductions from Aggregations providing Regulation Service are only eligible for payment for Energy when the real-time LBMP, at ~~its~~the Aggregation's Transmission Node, ~~forof the given interval~~ meets or exceeds the Net Benefits Test Threshold calculated in accordance with Section 4.5.7 of the Services Tariff for the applicable period~~, pursuant to Section 4.5.7 of this Services Tariff.~~ When ~~eligible~~the Net Benefits Test Threshold is satisfied, such Aggregations shall receive an Energy payment for Demand Reductions equal to the lower of ~~its~~the Demand Reductions' contribution to ~~either~~ the actual Energy provided or the

Aggregation's AGC Base Point Signal. ~~Demand Side Resources providing Regulation Service shall not receive a settlement payment for Energy.~~

~~B~~C. For any hour in which a Limited Energy Storage Resource ~~(~~or Aggregation of Limited Energy Storage Resources~~thereof)~~ has injected or withdrawn Energy, pursuant to an ISO schedule to do so, it shall receive a settlement payment (if the amount calculated below is positive) or charge (if the amount calculated below is negative) for Energy pursuant to the following formula:

$$Energy\ Settlements_h = Net\ MWHR_h * LBMP_h$$

Where:

$Net\ MWHR_h$ = the amount of Energy injected by the Limited Energy Storage Resource in hour *h* minus the amount of Energy withdrawn by that Limited Energy Storage Resource in hour *h*

$LBMP_h$ = the time-weighted average LBMP in hour *h* calculated for the location of that Limited Energy Storage Resource

15.3.6.2 Additional Payments/Charges

For any interval in which a ~~Generator~~ Supplier that is providing Regulation Service receives an AGC Base Point Signal that differs from 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, provided however no RRAP shall be payable and no RRAC shall be charged to a Limited Energy Storage Resource ~~(~~or Aggregation ~~thereof)~~of Limited Energy Storage Resources.

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

For any interval in which a ~~Generator~~ Supplier 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 RRAP or RRAC calculated under the terms of this subsection. If the Energy Bid Price of such a ~~Generator~~ Supplier is higher than the LBMP at its location in that interval, the ~~Generator~~ Supplier shall receive a RRAP. Conversely, for any interval in which such a ~~Generator's~~ Supplier's Energy Bid Price is lower than the LBMP at is location at that interval, the ~~Generator~~ Supplier shall be assessed a RRAC. RRAPs and RRACs shall be calculated using the following formula:

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

Where:

S = the number of seconds in the RTD interval;

If the result of the calculation is positive then the ~~Generator~~ Supplier shall receive a RRAP. If it is negative then the ~~Generator~~ Supplier shall be subject to a RRAC. For purposes of applying this formula, whenever the ~~Generator's~~ Supplier's actual Bid exceeds the applicable LBMP the "Bid" term shall be set at a level equal to the lesser of the ~~Generator's~~ Supplier's actual Bid or its reference Bid plus $100/MWh. ~~Demand Side Resources providing Regulation Service shall not be eligible for a RRAP and not liable for an RRAC.~~

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

For any interval in which a ~~Generator~~ Supplier 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~~ Supplier is higher than the LBMP at its location in that interval, the ~~Generator~~ Supplier shall be assessed a RRAC. Conversely, for any interval in which such a

~~Generator's~~ Supplier's Energy Bid Price is lower than the LBMP at its location in that interval, the ~~Generator~~ Supplier shall receive a RRAP. RRAPs and RRACs shall be calculated using the following formula:

$$Payment/Charge = \int_{min(RTD\ BasePoint\ Signal, max(AGC\ BasePoint\ Signal, Actual\ Output))}^{RTD\ BasePoint\ Signal} -[Bid - LBMP] * S/3600$$

Where:

S = the number of seconds in the RTD interval;

If the result of the calculation is positive then the ~~Generator~~ Supplier shall receive a RRAP. If it is negative then the ~~Generator~~ Supplier shall be subject to a RRAC. For purposes of this formula, whenever the ~~Generator's~~ Supplier'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~~ Supplier's actual Bid or its reference Bid minus $100/MWh.

~~Demand Side Resources providing Regulation Service shall not be eligible for a RRAP and not liable for an RRAC.~~

15.3.7 Regulation Service Demand Curve

The ISO shall establish a Regulation Service Demand Curve that will apply to both the Day-Ahead and real-time Regulation Capacity Market Price and settlements. The Regulation Capacity Market Prices calculated pursuant to Sections 15.3.4.1 and 15.3.5.1 of this Rate Schedule shall take account of the demand curve established in this Section so that Regulation Capacity is not scheduled by SCUC, RTC, or RTD at a cost higher than the demand curve indicates should be paid in the relevant market.

The ISO shall establish and post a target level of Regulation Service for each hour, which will be the number of MW of Regulation Capacity that the ISO would seek to maintain as its

Regulation Service requirement in that hour. The ISO will then define a Regulation Service demand curve for that hour as follows:

For quantities of Regulation Capacity that are less than or equal to the target level of Regulation Service minus 80 MW, the price on the Regulation Service demand curve shall be $775/MW.

For quantities of Regulation Capacity that are less than or equal to the target level of Regulation Service minus 25 MW but that exceed the target level of Regulation Service minus 80 MW, the price on the Regulation Service demand curve shall be $525/MW.

For quantities of Regulation Capacity that are less than or equal to the target level of Regulation Service but that exceed the target level of Regulation Service minus 25 MW, the price on the Regulation Service demand curve shall be $25/MW.

For all other quantities, the price on the Regulation Service demand curve shall be $0/MW. However, the ISO shall not schedule more Regulation Service than the target level for the requirement for that hour.

In order to respond to operational or reliability problems that arise in real-time, the ISO may procure Regulation Capacity at a quantity and/or price point different than those specified above. The ISO shall post a notice of any such purchase as soon as reasonably possible and shall report on the reasons for such purchases at the next meeting of its Business Issues Committee. The ISO shall also immediately initiate an investigation to determine whether it is necessary to modify the quantity and price points specified above to avoid future operational or reliability problems. The ISO will consult with its Market Monitoring Unit when it conducts this investigation.

If the ISO determines that it is necessary to modify the quantity and/or price points specified above in order to avoid future operational or reliability problems it may temporarily modify them for a period of up to ninety days. If circumstances reasonably allow, the ISO will consult with its Market Monitoring Unit, the Business Issues Committee, the Commission, and the PSC before implementing any such modification. In all circumstances, the ISO will consult with those entities as soon as reasonably possible after implementing a temporary modification.

Not later than 90 days after the implementation of the Regulation Service Demand Curve the ISO, in consultation with its Advisor, shall conduct an initial review in accordance with the ISO Procedures. The scope of the review shall be upward or downward in order to optimize the economic efficiency of any, or all, the ISO-Administered Markets. The ISO and the Market Advisor shall perform additional quarterly reviews, subject to the same scope requirement, during the remainder of the first year that this Section 15.3.7 is in effect. After the first year, the ISO shall perform periodic reviews, subject to the same scope requirement, and the Market Monitoring Unit shall be given the opportunity to review and comment on the ISO's periodic reviews of the Regulation Service Demand Curve.

The responsibilities of the Market Monitoring Unit that are addressed in the above section of Rate Schedule 3 to the Services Tariff are also addressed in Section 30.4.6.4.1 of Attachment O.

15.3.8 Temporary Suspension of Regulation Service Markets During Reserve Pickups and Maximum Generation

During any period in which the ISO has activated its RTD-CAM software and called for a "large event" or "small event" reserve or maximum generation pickup, as described in Article 4.4.4.1 of this ISO Services Tariff, the ISO will set all Regulation Service schedules to zero~~.~~, The

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ISO will establish real-time Regulation Market Prices for Regulation Capacity and Regulation Movement of zero for settlement and balancing purposes. The ISO will restore real-time Regulation Service schedules as soon as possible after the end of the reserve or maximum generation pickup.

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15.3A Rate Schedule "3-A" - Charges Applicable to Suppliers That Are Not Providing Regulation Service

15.3A.1 Persistent Undergeneration Charges

A Supplier, other than a Supplier included in Section 15.3A.2 of this Rate Schedule, that is not providing Regulation Service, that persistently operates at a level below its ~~Energy~~ schedule to provide Energy shall pay a persistent undergeneration charge to the ISO, unless its operation is within a tolerance described below, provided, however, no persistent undergeneration charges shall apply to a Fixed Block Unit that has reached a percentage of its Normal Upper Operating Limit, which percentage shall be set pursuant to ISO Procedures and shall be initially set at seventy percent (70%). Persistent undergeneration charges per interval shall be calculated as follows:

$$\text{Persistent undergeneration charge} = \text{Energy Difference} \times \text{Max}(MPRC_{DAM}, MPRC_{RT}) \times \text{Length of Interval in seconds}/3600 \text{ seconds}$$

Where:

Energy Difference in (MW) is determined by subtracting the actual Energy provided by the Supplier from its RTD Base Point Signal for the dispatch interval. The Energy Difference shall be set at zero for any Energy Difference that is otherwise negative or that falls within a tolerance, set pursuant to ISO Procedures, and which shall contain a steady-state and a dynamic component. The steady-state component shall initially be 3% of the Supplier's Normal Upper Operating Limit or Emergency Upper Operating Limit, as applicable, and the dynamic component shall be a time constant that shall initially be set at fifteen minutes;

$MPRC_{DAM}$ is the Regulation Capacity Market Price in the Day-Ahead Market; and

$MPRC_{RT}$ is the Regulation Capacity Market Price in the Real-Time Market.

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15.3A.1.2 Persistent Over-Withdrawal Charges

An Energy Storage Resource, ~~(or~~ an Aggregation ~~thereof)~~of Energy Storage Resources, or DER Aggregation ~~with~~that includes at least one Withdrawal-Eligible Generator that is (a) scheduled to withdraw~~ing~~ Energy, (b) not providing Regulation Services, and (c) persistently ~~withdraws~~ withdrawing Energy at a level exceeding its withdrawal schedule, shall pay a persistent over-withdrawal charge to the ISO~~,~~ unless its operation is within the applicable tolerance described below. Persistent over-withdrawal charges per interval shall be calculated as follows:

Persistent Over-Withdrawal Charge = Energy Difference x Max ($MPRC_{DAM}$, $MPRC_{RT}$) x Length of Interval in seconds/3600 seconds

Where:

Energy Difference in (MW) is determined by subtracting the Resource's actual energy operating level from its RTD Base Point Signal. The Energy Difference shall be set at zero for any Energy Difference that is otherwise negative or that falls within a tolerance, set pursuant to ISO Procedures, and which shall contain a steady-state and a dynamic component. The steady-state component shall initially be an absolute value of 3% of the Resource's Maximum Withdrawal Limit, as applicable, and the dynamic component shall be a time constant that shall initially be set at fifteen minutes;

$MPRC_{DAM}$ is the Regulation Capacity Market Price in the Day-Ahead Market; and

$MPRC_{RT}$ is the Regulation Capacity Market Price in the Real-Time Market.

15.3A.1.1 Overgeneration Charges

An Intermittent Power Resource~~)~~ that depends on wind as its fuel, for which the ISO has imposed a Wind Output Limit after October 31, 2009, or after February 1, 2010 for an

Intermittent Power Resource that depends on wind as its fuel in commercial operation before 2006 with nameplate capacity of 30 MWs or less, that operates at a level above its schedule shall pay an overgeneration charge to the ISO, unless its operation is within a tolerance described below.

Overgeneration charges per interval shall be calculated as follows:

$$\text{Overgeneration charge} = \text{Energy Difference} \times \text{Max}(MPRC_{DAM}, MPRC_{RT}) \times \text{Length of Interval in seconds}/3600 \text{ seconds}$$

Where:

Energy Difference in (MW) is determined by subtracting the RTD Base Point Signal for the dispatch interval from the actual Energy provided by the Intermittent Power Resource for the same interval. The Energy Difference shall be set at zero for any Energy Difference that is otherwise negative or that falls within a tolerance, set pursuant to ISO Procedures, which shall initially be set at 3% of the Supplier's Normal Upper Operating Limit or Emergency Upper Operating Limit, as applicable;

$MPRC_{DAM}$ is the Regulation Capacity Market Price in the Day-Ahead Market; and

$MPRC_{RT}$ is the Regulation Capacity Market Price in the Real-Time Market

15.3A.2 Exemptions

The following types of Generator shall not be subject to persistent undergeneration charges:

15.3A.2.1 Generators, except for the Generator of a Behind-the-Meter Net Generation Resource and a Generator in an Aggregation, providing Energy under contracts (including PURPA contracts), executed and effective on or before November 18, 1999, in which the power purchaser does not control the operation of the supply source but would be responsible for payment of the persistent undergeneration or performance charge;

15.3A.2.2 Existing topping turbine Generators and extraction turbine Generators producing electric Energy resulting from the supply of steam to the district steam system in operation on or before November 18, 1999 and/or topping or extraction turbine Generators utilized in replacing or repowering existing steam supplies from such units (in accordance with good engineering and economic design) that cannot follow schedules, up to a maximum total of 523 MW of such units;

15.3A.2.3 Limited Control Run of River Hydro Resources;

15.3A.2.4 Intermittent Power Resources ~~(~~and Aggregations ~~thereof)~~of Intermittent Power Resources that depend on wind, landfill gas, or solar energy as their fuel;

15.3A.2.5 Capacity Limited Resources, ~~and~~Aggregations of Capacity Limited Resources, Energy Limited Resources ~~(~~and Aggregations ~~thereof)~~of Energy Limited Resources, to the extent that their real-time Energy injections are equal to or greater than their bid-in upper operating limits but are less than their Real-Time Scheduled Energy Injections;

15.3A.2.6 Generators operating in their Start-Up Period or their Shutdown Period and, for Generators comprised of a group of generating units at a single location, which grouped generating units are separately committed and dispatched by the ISO, and for which Energy injections are measured at a single location, each of the grouped generating units when one of the grouped generating units is operating in its Start-Up or Shutdown Period; and

15.3A.2.7 Generators operating during a Testing Period.

15.3A.2.8 ~~Withdrawing~~ Energy Storage Resources with schedules to withdraw Energy are instead subject to persistent over-withdrawal charges.

For Generators and Resources described in Sections 15.3A.2.1, 15.3A.2.2, 15.3A.2.3, and 15.3A.2.4 above, this exemption shall not apply in an hour if the Generator or Resource has bid in that hour as ISO-Committed Flexible or Self-Committed Flexible.

15.4 Rate Schedule 4 - Payments for Supplying Operating Reserves

This Rate Schedule applies to payments to Suppliers that provide Operating Reserves to the ISO. Transmission Customers will purchase Operating Reserves from the ISO under Rate Schedule 5 of the ISO OATT.

15.4.1 General Responsibilities and Requirements

15.4.1.1 ISO Responsibilities

The ISO shall procure on behalf of its Customers a sufficient quantity of Operating Reserve products to comply with the Reliability Rules and with other applicable reliability standards, as well as Scarcity Reserve Requirements. These quantities shall be established under Section 15.4.7 of this Rate Schedule for locational Operating Reserve requirements and Section 15.4.6.2 of this Rate Schedule for Scarcity Reserve Requirements. To the extent that the ISO enters into Operating Reserve sharing agreements with neighboring Control Areas its Operating Reserves requirements shall be adjusted as, and where, appropriate.

The ISO shall define requirements for Spinning Reserve, which may be met only by Suppliers that are eligible, under Section 15.4.1.2 of this Rate Schedule, to provide Spinning Reserve; 10-Minute Reserve, which may be met by Suppliers that are eligible to provide either Spinning Reserve or 10-Minute Non-Synchronized Reserve; and 30-Minute Reserve, which may be met by Suppliers that are eligible to provide any Operating Reserve product. The ISO shall also define locational requirements for Spinning Reserve, 10-Minute Reserve, and 30-Minute Reserve located East of Central-East, in Southeastern New York and on Long Island. In addition to being subject to the preceding limitations on Suppliers that can meet each of these requirements, the requirements for Operating Reserve located East of Central-East may only be met by eligible Suppliers that are located East of Central-East, requirements for Operating Reserve located in Southeastern New York may only be met by eligible Suppliers that are located in Southeastern New York, and requirements for Operating Reserve located on Long Island may only be met 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 also establish Scarcity Reserve Requirements in the Real-Time Market pursuant to Section 15.4.6.2 of this Rate Schedule, which may be met by Suppliers eligible to provide 30-Minute Reserve. Scarcity Reserve Requirements may only be met by eligible Suppliers that are located in the Scarcity Reserve Region associated with a given Scarcity Reserve Requirement. The ISO shall select Suppliers of Operating Reserves products to meet these requirements, including the locational Operating Reserves requirements and Scarcity Reserve 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 15.4.7 of this Rate Schedule and Scarcity Reserve Requirements determined consistently with the requirements of Section 15.4.6.2 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 15.4.5.1 and 15.4.6.1 of this Rate Schedule).

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15.4.1.2 Supplier Eligibility Criteria

The ISO shall enforce the following criteria, which define which types of Suppliers are eligible to supply particular Operating Reserve products.

15.4.1.2.1 Spinning Reserve:

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 that meet the criteria set forth in the ISO Procedures shall be eligible to supply Spinning Reserve. ~~(except for Demand Side Resources that are Local Generators not utilizing inverter-based energy storage technology, DER Coordinator Entity~~ The following types of resources are only eligible to provide Spinning Reserve if all of the generating units use inverter-based energy storage technology and meet the criteria set forth in the ISO Procedures: (a) Aggregations comprised of one or more generating units ~~(unless each of those excluding Aggregations where each generating units usesconsists of inverter-based energy storage technology)~~, (b) Aggregations that include Demand Side Resource(s) where at least one Demand Side Resource facilitates its Demand Reduction by utilizing a Local Generator~~(unless that Local Generator uses inverter-based energy storage technology),~~ and (c) Behind-the-Meter Net Generation Resources that are comprised of more than one generating unit and dispatched as a single aggregate unit~~)~~. Suppliers utilizing inverter-based energy storage technology, ~~including Aggregations with a combination of individual DER utilizing inverter-based energy storage technology and/or Demand Side Resources,~~ and that meet the criteria set forth in the ISO Procedures, shall be eligible to supply Spinning Reserve when withdrawing or injecting Energy, and when idle.

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15.4.1.2.2 10-Minute Non-Synchronized Reserve:

(i) Off-line Generators that are capable of starting, synchronizing, and increasing their output level within ten (10) minutes, (ii) Behind-the-Meter Net Generation Resources that are comprised of more than one generating unit and dispatched as a single aggregate unit that are capable of increasing their output level within ten (10) minutes, ~~and (iii) Demand Side Resources that are capable of reducing their Energy usage within ten (10) minutes~~, and (iii) Aggregations comprised solely of ~~one or more~~ generating units ~~and~~ that are capable of increasing their supply level within ten (10) minutes, that meet the criteria set forth in the ISO Procedures shall be eligible to supply 10-Minute Non-Synchronized Reserve.

15.4.1.2.3 30-Minute Reserve:

Generators, except Behind-the-Meter Net Generation Resources and Aggregations that are comprised of more than one generating unit ~~and dispatched as a single aggregate unit~~, that are ISO-Committed Flexible or Self-Committed Flexible and operating within the dispatchable portion of their operating range shall be eligible to supply synchronized 30-Minute Reserves. ~~and~~ Aggregations that includeing Demand Side Resource(s) that do not facilitate demand reduction using Local Generators, or that facilitate demand reduction using a Local Generator utilizing inverter-based energy storage technology, that are capable of reducing their Energy usage within thirty (30) minutes shall be eligible to supply synchronized 30-Minute Reserves. Suppliers utilizing inverter-based energy storage technology, including Aggregations with a combination of ~~individual DER~~Resources utilizing inverter-based energy storage technology and~~/or~~ Demand Side Resources, and that meet the criteria set forth in the ISO Procedures, shall be eligible to supply synchronized 30-Minute Reserves when withdrawing or when injecting Energy, and when idle. Finally, (i) Off-line Generators that are capable of starting, synchronizing, and increasing their output level within thirty (30) minutes, (ii) Behind-the-Meter Net Generation Resources that are comprised of more than one generating unit and dispatched as a single aggregate unit that are capable of increasing their output level within thirty (30) minutes, and (iii) Aggregations comprised of one or more generating units ~~and~~ that are capable of increasing their output level within thirty (30) minutes, ~~and (iii~~iv~~) Demand Side Resources that are capable of reducing their Energy usage within thirty (30) minutes,~~ that meet the criteria set forth in the ISO Procedures shall be eligible to supply non-synchronized 30-Minute Reserves.

15.4.1.2.4 Self-Committed Fixed and ISO-Committed Fixed Generators and Aggregations:

Shall not be eligible to provide any kind of Operating Reserve.

15.4.1.3 Other Supplier Requirements

All Suppliers of Operating Reserve must be located within the NYCA and must be under ISO Operational Control. Each Supplier bidding to supply Operating Reserve or reduce demand must be able to provide Energy or reduce demand consistent with the Reliability Rules and the ISO Procedures when called upon by the ISO.

All Suppliers that are selected to provide Operating Reserves shall ensure that their Resources maintain and deliver the appropriate quantity of Energy, or reduce the appropriate quantity of demand, when called upon by the ISO during any interval in which they have been selected.

~~Generators or Demand Side Resources~~Suppliers that are selected to provide Operating Reserve in the Day-Ahead Market ~~or any supplemental commitment~~ may increase their Incremental Energy Bids ~~or Demand Reduction Bids, respectively,~~ for portions of their Resources that have been scheduled ~~through those processes~~; provided however, that they are not otherwise prohibited from doing so pursuant to other provisions of the ISO's Tariffs. Withdrawal-Eligible Generators or Aggregations comprised of one or more Withdrawal-Eligible Generators that are scheduled to withdraw Energy, and that are selected to provide Operating Reserve in the Day-Ahead Market ~~or any supplemental commitment~~, may decrease their Bids to withdraw Energy for portions of their resources that have been scheduled through those processes; provided however, that they are not otherwise prohibited from doing so pursuant to other provisions of the ISO's Tariffs. ~~Generators or Demand Side Resources~~Suppliers that are selected to provide Operating Reserve in the Day-Ahead Market ~~or any supplemental commitment~~ may not, however, reduce the UOL_N in their Real-Time Market Bids below the sum of their Day-Ahead Market schedules for Energy, Operating Reserve, and Regulation Service ~~Energy and Ancillary Services or supplemental commitments in real-time,~~ except to the extent that they are directed to do so by the ISO. The ISO may reduce the real-time Operating Reserve schedule (in MW) from an Energy Storage Resource to account for the Energy Level of such Resource, as discussed in Section 4.4.2.1 of this ISO Services Tariff.~~Generators and Demand Side Resources~~ Suppliers may enter into alternate sales arrangements utilizing any Capacity that has not been scheduled to provide Operating Reserve.

15.4.2 General Day-Ahead Market Rules

15.4.2.1 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 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 least of the Resource's emergency response rate multiplied by ten, or the Resource's applicable Upper Operating Limit (*i.e.*, UOL_N, UOL_E); (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 least of the Resource's emergency response rate multiplied by twenty and its applicable Upper Operating Limit.

However, the sum of the amount of Energy ~~or Demand Reduction~~ 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. For an Energy Storage Resource or an Aggregation of Energy Storage Resources, the Resource's Energy schedule minus its Regulation Service schedule shall not be less than the Resource's Lower Operating Limit.

For an Energy Limited Resource ~~(~~or Aggregation ~~thereof)~~of Energy Limited Resources that is withdrawing Energy, the sum of the Resource's or Aggregation's Energy Schedule, the amount of Regulation Capacity it is scheduled to provide, and the amount of each Operating Reserves product it is scheduled to provide shall not exceed the lesser of zero or its Upper Operating Limit. For an Energy Storage Resource ~~(~~or Aggregation ~~thereof)~~of Energy Storage Resources that is withdrawing Energy, the sum of the Resource's or Aggregation's Energy

Schedule, the amount of Regulation Capacity it is scheduled to provide, and the amount of Operating Reserves product it is scheduled to provide shall not exceed its Upper Operating Limit.

The ISO shall select Operating Reserve Suppliers for each hour of the upcoming day through a co-optimized Day-Ahead commitment process that minimizes the total bid cost of Energy, Operating Reserves and Regulation Service, using Bids submitted pursuant to Article 4.2 of, and Attachment D to, this ISO Services Tariff. As part of the co-optimization process, the ISO shall determine how much of each Operating Reserves product particular Suppliers will be required to provide in light of the Reliability Rules and other applicable reliability standards, including the locational Operating Reserves requirements specified above.

15.4.2.2 ISO Notice Requirement

The ISO shall notify each Operating Reserve Supplier that has been selected in the Day-Ahead Market of the amount of each Operating Reserve product that it has been scheduled to provide.

15.4.2.3 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 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

15.4.6.3 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.

15.4.3 General Real-Time Market Rules

15.4.3.1 Bid Selection

The ISO will automatically select Operating Reserves Suppliers in real-time from eligible Resources, that submit Real-Time Bids pursuant to Section 4.4 of, and Attachment D to, this ISO Services Tariff. Each Supplier 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 least of the Resource's emergency response rate multiplied by ten and the Resource's applicable Upper Operating Limit (UOL_N or UOL_E); (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 least of the Resource's emergency response rate multiplied by twenty and the Resource's applicable Upper Operating Limit (UOL_N or UOL_E). However, the sum of the amount of Energy ~~or 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.

For an Energy Limited Resource ~~(~~or an Aggregation ~~thereof)~~of Energy Limited Resources that is withdrawing Energy, the sum of the Resource's or Aggregation's Energy schedule, the amount of Regulation Capacity it is scheduled to provide, and the amount of each Operating Reserves product it is scheduled to provide shall not exceed the lesser of zero or its UOL. For an Energy Storage Resource ~~(~~or an Aggregation ~~thereof)~~of Energy Storage Resources that is withdrawing Energy, the sum of the Resource's or Aggregation's Energy Schedule, the amount of Regulation Capacity it is scheduled to provide and the amount of Operating Reserves product it is scheduled to provide shall not exceed its UOL. The ISO may limit the availability of a Withdrawal-Eligible Generator to provide Operating Reserves based on its Energy Level constraints.

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 Service, and Operating Reserves. As part of the process, the ISO shall determine how much of each Operating Reserves product particular Suppliers will be required to provide in light of the Reliability Rules and other applicable reliability standards, including the locational Operating Reserves requirements and Scarcity Reserve Requirements specified above.

15.4.3.2 ISO Notice Requirement

The ISO shall notify each Supplier of Operating Reserve that has been scheduled by RTD of the amount of Operating Reserve that it must provide.

DRAFT – FOR DISCUSSION PURPOSES ONLY
For discussion at April 2019 Management Committee Meeting

15.4.3.3 Obligation to Make Resources Available to Provide Operating Reserves

Any Resource that is eligible to supply Operating Reserves and that is made available to ISO for dispatch in Real-Time must also make itself available to provide Operating Reserves.

15.4.3.4 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.

15.4.3.5 Performance Tracking and Supplier Disqualifications

When a Supplier committed to supply Operating Reserves is activated, the ISO shall measure and track its actual Energy injections, ~~and~~ withdrawals, and ~~supplied or its~~ Demand Reductions against its expected performance in real-time. The ISO may disqualify Suppliers that consistently fail to provide Energy, ~~or~~ Demand Reduction, or to reduce Energy withdrawals, 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.

15.4.4 Operating Reserves Settlements - General Rules

15.4.4.1 Establishing Locational Reserve and Scarcity Reserve Requirement Prices

Except as noted below, the ISO shall calculate separate Day-Ahead Market and Real-Time Market prices for each of the products in four locations: (i) West of Central-East ("West" or "Western"); (ii) East of Central-East excluding Southeastern New York ("Eastern"); (iii) Southeastern New York excluding Long Island ("Southeastern"); and (iv) Long Island ("L.I."). The ISO will thus calculate twelve different locational Operating Reserve prices in both the Day-

Ahead Market and the Real-Time Market. The ISO will also calculate prices in the Real-Time Market for each of the products in a Scarcity Reserve Region, if applicable. Day-Ahead locational reserve prices shall be calculated pursuant to Section 15.4.5 of this Rate Schedule. Real-Time locational Operating Reserves prices and Scarcity Reserve Requirement prices shall be calculated pursuant to Section 15.4.6 of this Rate Schedule

15.4.4.2 Settlements Involving Suppliers of Operating Reserves Located on Long Island

Suppliers of Operating Reserves located on Long Island shall receive settlement payments as if they were providing Operating Reserves located in Southeastern New York, except in the case of a Scarcity Reserve Requirement for a Scarcity Reserve Region that includes Long Island in addition to one or more other Load Zones. In this instance, suppliers of Operating Reserves located on Long Island shall receive settlement payments as if they were providing Operating Reserves located in Southeastern New York and in the applicable Scarcity Reserve Region. The ISO will calculate separate locational Long Island Operating Reserves prices and Long Island Scarcity Reserve Requirement prices for Scarcity Reserve Regions that include Long Island but will not post them or use them for settlement purposes.

15.4.4.3 "Cascading" of Operating Reserves

The ISO will deem Spinning Reserve to be the "highest quality" Operating Reserve, followed by 10-Minute Non-Synchronized Reserve and by 30-Minute Reserve. The ISO shall substitute higher quality Operating Reserves in place of lower quality Operating Reserves, when doing so lowers the total as-bid cost, *i.e.*, when the marginal cost for the higher quality Operating Reserve product is lower than the marginal cost for the lower quality Operating Reserve product, and the substitution of a higher quality for the lower quality product does not cause locational

Operating Reserve requirements or Scarcity Reserve Requirements to be violated. To the extent, however, that reliability standards require the use of higher quality Operating Reserves, substitution cannot be made in the opposite direction.

The market clearing price of higher quality Operating Reserves will not be set at a price below the market clearing price of lower quality Operating Reserves in the same location or Scarcity Reserve Region. Thus, the market clearing price of Spinning Reserves will not be below the price for 10-Minute Non-Synchronized Reserves or 30-Minute Reserves and the market clearing price for 10-Minute Non-Synchronized Reserves will not be below the market clearing price for 30-Minute Reserves.

15.4.5 Operating Reserve Settlements – Day-Ahead Market

15.4.5.1 Calculation of Day-Ahead Market Clearing Prices

The ISO shall calculate hourly Day-Ahead Market clearing prices for each Operating Reserve product at each location. Each Day-Ahead Market clearing price shall equal the sum of the relevant Day-Ahead locational Shadow Prices for that product in that hour, subject to the restriction described in Section 15.4.4.3 of this Rate Schedule.

The Day-Ahead Market clearing price for a particular Operating Reserve product in 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 a particular location may be used to satisfy in a given hour. The ISO shall calculate Day-Ahead Market clearing prices using the following formulae:

Market clearing price for Western 30-Minute Reserves = SP1

Market clearing price for Western 10-Minute Non-Synchronized Reserves = SP1 + SP2

Market clearing price for Western Spinning Reserves = SP1 + SP2 + SP3

Market clearing price for Eastern 30-Minute Reserves = SP1 + SP4

Market clearing price for Eastern 10-Minute Non-Synchronized Reserves = SP1 + SP2 + SP4 + SP5

Market clearing price for Eastern Spinning Reserves = SP1 + SP2 + SP3 + SP4 + SP5 + SP6

Market clearing price for Southeastern 30-Minute Reserves = SP1 + SP4 + SP7

Market clearing price for Southeastern 10-Minute Non-Synchronized Reserves = SP1 + SP2 + SP4 + SP5 + SP7 + SP8

Market clearing price for Southeastern Spinning Reserves = SP1 + SP2 + SP3 + SP4 + SP5 + SP6 + SP7 + SP8 + SP9

Market clearing price for L.I. 30-Minute Reserves = SP1 + SP4 + SP7 + SP10

Market clearing price for L.I. 10-Minute Non-Synchronized Reserves = SP1 + SP2 + SP4 + SP5 + SP7 + SP8 + SP10 + SP11

Market clearing price for L.I. Spinning Reserves = SP1 + SP2 + SP3 + SP4 + SP5 + SP6 + SP7 + SP8 + SP9 + SP10 + SP11 + SP12

Where:

SP1 = Shadow Price for total 30-Minute Reserve requirement constraint for the hour

SP2 = Shadow Price for total 10-Minute Reserve requirement constraint for the hour

SP3 = Shadow Price for total Spinning Reserve requirement constraint for the hour

SP4 = Shadow Price for Eastern, Southeastern, or L.I. 30-Minute Reserve requirement constraint for the hour

SP5 = Shadow Price for Eastern, Southeastern, or L.I. 10-Minute Reserve requirement constraint for the hour

SP6 = Shadow Price for Eastern, Southeastern, or L.I. Spinning Reserve requirement constraint for the hour

SP7 = Shadow Price for Southeastern, or L.I. 30-Minute Reserve requirement constraint for the hour

SP8 = Shadow Price for Southeastern, or L.I. 10-Minute Reserve requirement constraint for the hour

SP9 =Shadow Price for Southeastern, or L.I. Spinning Reserve requirement constraint for the hour

SP10 = Shadow Price for Long Island 30-Minute Reserve requirement constraint for the hour

SP11 = Shadow Price for Long Island 10-Minute Reserve requirement constraint for the hour

SP12 = Shadow Price for Long Island Spinning Reserve requirement constraint for the hour

Day-Ahead locational Shadow Prices will be calculated by SCUC. Each hourly Day-Ahead Shadow Price for each Operating Reserves requirement shall equal the marginal Bid cost of scheduling Resources to provide additional Operating Reserves to meet that requirement in that hour, including any impact on the Bid Production Cost of procuring Energy or Regulation Service that would result from procuring an increment of Operating Reserve to meet the requirement in that hour, as calculated during the fifth SCUC pass described in Section 17.1.3 of Attachment B to this Services Tariff. As a result, the Shadow Price for each Operating Reserves requirement shall include the Day-Ahead Availability Bid of the marginal Resource selected to meet that requirement (or the applicable price on the Operating Reserve Demand Curve for that requirement during shortage conditions), plus any margins on the sale of Energy or Regulation Service in the Day-Ahead Market that that Resource would forego if scheduling it to provide additional Operating Reserve to meet that requirement would lead to it being scheduled to provide less Energy or Regulation Service. Shadow Prices will also be consistent with the Operating Reserve Demand Curves described in Section 15.4.7 of this Rate Schedule, which will ensure that Operating Reserves are not scheduled by SCUC at a cost greater than the relevant Operating Reserve Demand Curve indicates should be paid. If more Operating Reserve of a particular quality than is needed is scheduled to meet a particular locational Operating Reserve requirement, the Shadow Price for that Operating Reserve requirement constraint shall be set at zero.

Each Supplier that is scheduled Day-Ahead to provide Operating Reserve shall be paid the applicable Day-Ahead 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 hour.

15.4.5.2 Other Day-Ahead Payments

A Supplier that bids on behalf of (i) a Generator that provides Operating Reserves or (ii) an ~~Demand Side Resource~~Aggregation that provides Operating Reserves may be eligible for a Day-Ahead Bid Production Cost guarantee payment pursuant to Section 4.6.6 and Attachment C of this ISO Services Tariff.

15.4.6 Operating Reserve Settlements – Real-Time Market

15.4.6.1 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 and Scarcity Reserve Region in each interval for which a Scarcity Reserve Requirement is established by the ISO. Each real-time market-clearing price shall equal the sum of the relevant real-time locational Shadow Prices and Scarcity Reserve Requirement Shadow Prices for a given product, subject to the restriction described in Section 15.4.4.3 of this Rate Schedule.

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

Market clearing price for Western 30-Minute Reserves = SP1

Market clearing price for Western 10-Minute Non-Synchronized Reserves = SP1 + SP2

Market clearing price for Western Spinning Reserves = SP1 + SP2 + SP3

Market clearing price for Eastern 30-Minute Reserves = SP1 + SP4

Market clearing price for Eastern 10-Minute Non-Synchronized Reserves = SP1 + SP2 + SP4 + SP5

Market clearing price for Eastern Spinning Reserves = SP1 + SP2 + SP3 + SP4 + SP5 + SP6

Market clearing price for Southeastern 30-Minute Reserves = SP1 + SP4 + SP7

Market clearing price for Southeastern 10-Minute Non-Synchronized Reserves = SP1 + SP2 + SP4 + SP5 + SP7 + SP8

Market clearing price for Southeastern Spinning Reserves = SP1 + SP2 + SP3 + SP4 + SP5 + SP6 + SP7 + SP8 + SP9

Market clearing price for L.I. 30-Minute Reserves = SP1 + SP4 + SP7 + SP10

Market clearing price for L.I. 10-Minute Non-Synchronized Reserves = SP1 + SP2 + SP4 + SP5 + SP7 + SP8 + SP10 + SP11

Market clearing price for L.I. Spinning Reserves = SP1 + SP2 + SP3 + SP4 + SP5 + SP6 + SP7 + SP8 + SP9 + SP10 + SP11 +SP12

Where:

SP1 = Shadow Price for total 30-Minute Reserve requirement constraint and, if applicable, Scarcity Reserve Requirement constraint for the interval

SP2 = Shadow Price for total 10-Minute Reserve requirement constraint for the interval

SP3 = Shadow Price for total Spinning Reserve requirement constraint for the interval

SP4 = Shadow Price for Eastern, Southeastern, or L.I. 30-Minute Reserve requirement constraint and, if applicable, Scarcity Reserve Requirement constraint for the interval

SP5 = Shadow Price for Eastern, Southeastern, or L.I. 10-Minute Reserve requirement constraint for the interval

SP6 = Shadow Price for Eastern, Southeastern, or L.I. Spinning Reserve requirement constraint for the interval

SP7 = Shadow Price for Southeastern, or L.I. 30-Minute Reserve requirement constraint and, if applicable, Scarcity Reserve Requirement constraint for the interval

SP8 = Shadow Price for Southeastern, or L.I. 10-Minute Reserve requirement constraint for the interval

SP9 = Shadow Price for Southeastern, or L.I. Spinning Reserve requirement constraint for the interval

SP10 = Shadow Price for Long Island 30-Minute Reserve requirement constraint and, if applicable, Scarcity Reserve Requirement constraint for the interval

SP11 = Shadow Price for Long Island 10-Minute Reserve requirement constraint for the interval

SP12 = Shadow Price for Long Island Spinning Reserve requirement constraint for the interval

Real-time locational and Scarcity Reserve Requirement Shadow Prices will be calculated by the ISO's RTD. Each Real-Time Shadow Price for each Operating Reserves requirement, including a Scarcity Reserve Requirement, in each RTD interval shall equal the marginal Bid cost of scheduling Resources to provide additional Operating Reserves to meet that requirement in that interval, including any impact on the Bid Production Cost of procuring Energy or Regulation Service that would result from procuring an increment of Operating Reserve to meet the requirement in that interval, as calculated during the second RTD pass described in Section 17.1.2.1.2.2 of Attachment B to this ISO Services Tariff. As a result, the Shadow Price for each Operating Reserves requirement, including a Scarcity Reserve Requirement, shall include the Real-Time Availability Bid of the marginal Resource selected to meet that requirement (or the applicable price on the Operating Reserve Demand Curve or Scarcity Reserve Demand Curve for that requirement during shortage conditions), plus any margins on the sale of Energy or Regulation Service in the Real-Time Market that that Resource would forego if scheduling it to provide additional Operating Reserve to meet that requirement would lead to it being scheduled to provide less Energy or Regulation Service. Shadow Prices will also be consistent with the Operating Reserve Demand Curves and Scarcity Reserve Demand Curve described in Section 15.4.7 of this Rate Schedule, which will ensure that Operating Reserves are not scheduled by RTC at a cost greater than the relevant Operating Reserve Demand Curve or Scarcity 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 or Scarcity Reserve Requirement then the Shadow Price for that Operating Reserve requirement or Scarcity 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.

15.4.6.1.1 The Real-Time Market clearing price shall also reflect the Shadow Price for any Scarcity Reserve Requirement constraint as part of the applicable 30-Minute Reserve requirement constraint Shadow Price for the Load Zones included in the Scarcity Reserve Region. The inclusion of Scarcity Reserve Requirement constraint Shadow Prices in the calculation of Real-Time Market clearing prices is as set forth below:

(a) When the Load Zones included in a Scarcity Reserve Region are identical to the Load Zones of an existing locational reserve region, the Scarcity Reserve Requirement will be added to the existing 30-Minute Reserve requirement for the locational reserve region and the Shadow Price for the Scarcity Reserve Requirement will be the Shadow Price for the revised 30-Minute Reserve requirement. The use of Scarcity Reserve Requirement Shadow Prices in calculating Real-Time Market clearing in such circumstances is as follows:

i. If the Scarcity Reserve Requirement is for a Scarcity Reserve Region that includes Load Zones A, B, C, D, E, F, G, H, I, J and K (*i.e.*, all Load Zones), then the Shadow Price for the Scarcity Reserve Requirement shall be SP1. SP1 shall be utilized in the same manner as described in the formulae above in calculating Real-Time Market clearing prices;

ii. If the Scarcity Reserve Requirement is for a Scarcity Reserve Region that includes Load Zones F, G, H, I, J and K (*i.e.*, all East of Central-East Load Zones), but does not include Load Zones A, B, C, D or E, then the Shadow Price for the Scarcity Reserve Requirement shall be SP4. SP4 shall be utilized in the same manner as described in the formulae above in calculating Real-Time Market clearing prices;

iii. If the Scarcity Reserve Requirement is for a Scarcity Reserve Region that includes Load Zones G, H, I, J and K (*i.e.*, all Southeastern New York Load Zones), but does not include Load Zones A, B, C, D, E or F, then the Shadow Price for the Scarcity Reserve Requirement shall be SP7. SP7 shall be utilized in the same manner as described in the formulae above in calculating Real-Time Market clearing prices; or

iv. If the Scarcity Reserve Requirement is for a Scarcity Reserve Region that includes Load Zone K (*i.e.*, Long Island only), but does not include Load Zones A, B, C, D, E, F, G, H, I or J, then the Shadow Price for the Scarcity Reserve Requirement shall be SP10. SP10 shall be utilized in the same manner as described in the formulae above in calculating Real-Time Market clearing prices.

(b) When the Load Zones included in the Scarcity Reserve Region are not identical to the Load Zones of an existing locational reserve region, the Shadow Price attributable to the Scarcity Reserve Requirement will be added to the applicable Shadow Price for the 30-Minute Reserve requirement for the existing locational reserve region to which all of the Load Zones included in the Scarcity Reserve Region belong. The inclusion of the Scarcity Reserve Requirement Shadow Prices shall apply only to the Load Zones included as part of a Scarcity Reserve Region. The use of Scarcity Reserve Requirement Shadow Prices in calculating Real-Time Market clearing in such circumstances is as follows:

i. If the Scarcity Reserve Requirement is for a Scarcity Reserve Region that includes at least one or more of Load Zones A, B, C, D or E and Section 15.4.6.1.1(a)(i) of this Rate Schedule is not applicable, then the Shadow Price for the Scarcity Reserve Requirement shall be included in SP1 for each of the Load Zones included in the Scarcity Reserve Region. This SP1 value shall be utilized in the same manner as described in the formulae above in calculating Real-Time

Market clearing prices for each of the Load Zones included in the Scarcity Reserve Region;

ii. If the Scarcity Reserve Requirement is for a Scarcity Reserve Region that includes at least Load Zone F, but does not include Load Zones A, B, C, D or E and Section 15.4.6.1.1(a)(ii) of this Rate Schedule is not applicable, then the Shadow Price for the Scarcity Reserve Requirement shall be included in SP4 for each of the Load Zones included in the Scarcity Reserve Region. This SP4 value shall be utilized in the same manner as described in the formulae above in calculating Real-Time Market clearing prices for each of the Load Zones included in the Scarcity Reserve Region; or

iii. If the Scarcity Reserve Requirement is for a Scarcity Reserve Region that includes at least one or more of Load Zones G, H, I or J, but does not include Load Zones A, B, C, D, E or F and Section 15.4.6.1.1(a)(iii) of this Rate Schedule is not applicable, then the Shadow Price for the Scarcity Reserve Requirement shall be included in SP7 for each of the Load Zones included in the Scarcity Reserve Region. This SP7 value shall be utilized in the same manner as described in the formulae above in calculating Real-Time Market clearing prices for each of the Load Zones included in the Scarcity Reserve Region.

15.4.6.2 Establishment of Scarcity Reserve Requirements in the Real-Time Market During EDRP/SCR Activations

The ISO will establish a Scarcity Reserve Requirement for each Scarcity Reserve Region when it has called upon the EDRP and/or SCRs in identified Load Zones to reduce Load to address a reliability need. The Scarcity Reserve Requirement will be applicable for all real-time intervals during which the ISO has activated EDRP and/or SCRs within the applicable Scarcity Reserve Region to provide Load reduction. The Scarcity Reserve Requirement for each affected real-time interval shall be an amount equal to the sum of the applicable values for the Expected EDRP/SCR MW for all of the Load Zones included in a Scarcity Reserve Region, less the Available Operating Capacity in the Scarcity Reserve Region; provided, however, that a Scarcity Reserve Requirement shall not have a value less than zero.

The applicable value of the Expected EDRP/SCR MW for each Load Zone included in a Scarcity Reserve Region to be used in calculating the Scarcity Reserve Requirement is dependent upon whether the Load reduction for a given interval is deemed voluntary or mandatory for purposes of calculating the Scarcity Reserve Requirement, as further described below. If the ISO has satisfied the notification requirements set forth in Section 5.12.11.1 of this ISO Services Tariff for the SCRs within any Load Zone for any hour encompassed by the EDRP/SCR activation(s) for the day at issue, the Load reduction for all intervals encompassed by such activation(s) are deemed to be mandatory for the purposes of calculating any Scarcity Reserve Requirement only and the corresponding value for a mandatory Load reduction is used for SCRs in determining any Scarcity Reserve Requirement. In all other circumstances not encompassed by the preceding sentence, the Load reduction for all intervals encompassed by such EDRP/SCR activation(s) are deemed to be voluntary for the day at issue and the corresponding value for a voluntary Load reduction is used for SCRs in determining any Scarcity Reserve Requirement. For EDRP, Load reduction is deemed to be voluntary in all intervals and the value for EDRP included in the Expected EDRP/SCR MW value for each Load Zone reflects the voluntary nature of the Load reduction.

15.4.6.3 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 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 or Scarcity Reserve Region; 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 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 or Scarcity Reserve Region; and (ii) the difference between the Supplier's Day-Ahead and real-time Operating Reserves schedules.

15.4.6.4 Other Real-Time Payments

The ISO shall pay Generators and Aggregations that are selected to provide Operating Reserves Day-Ahead, but are directed to convert to Energy production or, for Withdrawal-Eligible Generators and Aggregations that include Withdrawal-Eligible Generator(s), to reduce Energy withdrawals, in real-time, the applicable Real-Time LBMP for all Energy they are directed to provide in excess of their Day-Ahead Energy schedule.

A Supplier that bids on behalf of (i) a Generator that provides Operating Reserves or (ii) an ~~Demand Side Resource~~ Aggregation that provides Operating Reserves may be eligible for a Bid Production Cost guarantee payment pursuant to Section 4.6.6 and Attachment C of this ISO Services Tariff.

A Supplier that provides Operating Reserves may also be eligible for a Day-Ahead Margin Assurance Payment pursuant to Section 4.6.5 and Attachment J of this ISO Services Tariff.

15.4.7 Operating Reserve Demand Curves and Scarcity Reserve Demand Curve

The ISO shall establish twelve Operating Reserve Demand Curves, one for each locational Operating Reserves requirement. Specifically, there shall be a demand curve for: (i) Total Spinning Reserves; (ii) Eastern, Southeastern or Long Island Spinning Reserves; (iii) Southeastern or Long Island Spinning Reserves (iv) Long Island Spinning Reserves; (v) Total 10-Minute Reserves; (vi) Eastern, Southeastern or Long Island 10-Minute Reserves; (vii) Southeastern or Long Island 10-Minute Reserves; (viii) Long Island 10-Minute Reserves; (ix) Total 30-Minute Reserves (including separate demand curves applicable for each real-time interval the ISO has established a Scarcity Reserve Requirement); (x) Eastern, Southeastern or Long Island 30-Minute Reserves (including separate demand curves applicable for each real-time interval the ISO has established certain Scarcity Reserve Requirements); (xi) Southeastern or Long Island 30-Minute Reserves (including separate demand curves applicable for each real-time interval the ISO has established certain Scarcity Reserve Requirements); and (xii) Long Island 30-Minute Reserves (including a separate demand curve applicable for each real-time interval the ISO has established a Scarcity Reserve Requirement for which the pricing rules established in Section 15.4.6.1.1(a)(iv) of this Rate Schedule apply). Each Operating Reserve

Demand Curve will apply to both the Day-Ahead Market and the Real-Time Market for the relevant product and location, except for those demand curves that apply to certain Scarcity Reserve Requirements which will be applicable only during the real-time intervals that a Scarcity Reserve Requirement has been established by the ISO. The ISO shall also establish a Scarcity Reserve Demand Curve for each Scarcity Reserve Requirement established by the ISO in the Real-Time Market for which the pricing rules established in Section 15.4.6.1.1(b) of this Rate Schedule apply. A Scarcity Reserve Demand Curve will be applicable only during the real-time intervals that such a Scarcity Reserve Requirement has been established by the ISO.

The market clearing pricing for Operating Reserves shall be calculated pursuant to Sections 15.4.5.1 and 15.4.6.1 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, RTC or RTD at a cost higher than the relevant demand curve indicates should be paid.

The ISO Procedures shall establish and post a target level for each locational Operating Reserves requirement for each hour, which will be the number of MW of Operating Reserves meeting that requirement that the ISO would seek to maintain in that hour. To the extent not otherwise already adjusted pursuant to Section 15.4.6.1.1(a) of this Rate Schedule, during each real-time interval in which the ISO has established a Scarcity Reserve Requirement, the ISO will adjust the target level for the locational 30-Minute Reserves requirement to account for the Scarcity Reserve Requirement within the existing locational reserve region(s) to which all the Load Zones included in the Scarcity Reserve Region belong. The ISO will then define an Operating Reserves demand curve for that hour corresponding to each Operating Reserves requirement as follows:

(a) Total Spinning Reserves: For quantities of Operating Reserves meeting the total Spinning Reserves requirement that are less than or equal to the target level for that locational requirement, the price on the total Spinning Reserves demand curve shall be $775/MW. For all other quantities, the price on the total Spinning Reserves demand curve shall be $0/MW.

(b) Eastern, Southeastern or Long Island Spinning Reserves: For quantities of Operating Reserves meeting the Eastern, Southeastern or Long Island Spinning Reserves requirement that are less than or equal to the target level for that locational requirement, the price on the Eastern, Southeastern or Long Island Spinning Reserves demand curve shall be $25/MW. For all other quantities, the price on the Eastern, Southeastern or Long Island Spinning Reserves demand curve shall be $0/MW.

(c) Southeastern or Long Island Spinning Reserves: For quantities of Operating Reserves meeting the Southeastern or Long Island Spinning Reserves requirement that are less than or equal to the target level for that locational requirement, the price on the Southeastern or Long Island Spinning Reserves demand curve shall be $25/MW. For all other quantities, the price on the Southeastern or Long Island Spinning Reserves demand curve shall be $0/MW.

(d) Long Island Spinning Reserves: For quantities of Operating Reserves meeting the Long Island Spinning Reserves requirement that are less than or equal to the target level for that locational requirement, the price on the Long Island Spinning Reserves demand curve shall be $25/MW. For all other quantities, the price on the Long Island Spinning Reserves demand curve shall be $0/MW.

(e) Total 10-Minute Reserves: For quantities of Operating Reserves meeting the total 10-minute reserves requirement that are less than or equal to the target level for that locational requirement, the price on the total 10-minute reserves demand curve shall be $750/MW. For all other quantities, the price on the total 10-minute reserves demand curve shall be $0/MW.

(f) Eastern, Southeastern or Long Island 10-Minute Reserves: For quantities of Operating Reserves meeting the Eastern, Southeastern or Long Island 10-minute reserves requirement that are less than or equal to the target level for that locational requirement, the price on the Eastern, Southeastern or Long Island 10-minute reserves demand curve shall be $775/MW. For all other quantities, the price on the Eastern, Southeastern or Long Island 10-minute reserves demand curve shall be $0/MW.

(g) Southeastern or Long Island 10-Minute Reserves: For quantities of Operating Reserves meeting the Southeastern or Long Island 10-Minute Reserves requirement that are less than or equal to the target level for that locational requirement, the price on the Southeastern or Long Island 10-Minute Reserves demand curve shall be $25/MW. For all other quantities, the price on the Southeastern or Long Island 10-Minute Reserves demand curve shall be $0/MW.

(h) Long Island 10-Minute Reserves: For quantities of Operating Reserves meeting the Long Island 10-minute reserves requirement that are less than or equal to the target level for that locational requirement, the price on the Long Island 10-minute reserves demand curve shall be $25/MW. For all other quantities, the price on the Long Island 10-minute reserves demand curve shall be $0/MW.

(i) Total 30-Minute Reserves: For quantities of Operating Reserves meeting the total 30-Minute Reserves requirement that are less than or equal to the target level for that locational requirement minus 955 MW, the price on the total 30-Minute Reserves demand curve shall be $750/MW. For quantities of Operating Reserves meeting the total 30-Minute Reserves requirement that are less than or equal to the target level for that locational requirement minus 655 MW but that exceed the target level for that locational requirement minus 955 MW, the price on the total 30-Minute Reserves demand curve shall be $200/MW. For quantities of Operating Reserves meeting the total 30-Minute Reserves requirement that are less than or equal to the target level for that locational requirement minus 300 MW but that exceed the target level for that locational requirement minus 655 MW, the price on the total 30-Minute Reserves demand curve shall be $100/MW. For quantities of Operating Reserves meeting the total 30-Minute Reserves requirement that are less than or equal to the target level for that locational requirement but that exceed the target level for that locational requirement minus 300 MW, the price on the total 30-Minute Reserves demand curve shall be $25/MW. For all other quantities, the price on the total 30-Minute Reserves demand curve shall be $0/MW. However, the ISO will not schedule more total 30-Minute Reserves than the level defined by the requirement for that hour. During each real-time interval that the ISO has established a Scarcity Reserve Requirement in the Real-Time Market for which the pricing rules established in Section 15.4.6.1.1(a)(i) of this Rate Schedule apply, the applicable Operating Reserves demand curve for total 30-Minute Reserves shall be as follows: For quantities of Operating Reserves meeting the total 30-Minute Reserves locational requirement target level plus the Scarcity Reserve Requirement ("NYCA scarcity target level") that are less than or equal to the NYCA scarcity target level minus an amount equal to the sum of 955 MW and the Scarcity Reserve Requirement, the price on the total 30-Minute Reserves demand curve shall be $750/MW. For quantities of Operating Reserves meeting the NYCA scarcity target level that are less than or equal to the NYCA scarcity target level but that exceed the NYCA scarcity target level minus an amount equal to the sum of 955 MW and the Scarcity Reserve Requirement, the price on the total 30-Minute Reserves demand curve shall be $500/MW. For all other quantities, the price on the total 30-Minute Reserves demand curve shall be $0/MW. However, the ISO will not schedule more total 30-Minute Reserves than the level defined by the total 30-Minute Reserves locational requirement plus the Scarcity Reserve Requirement for that interval.

During each real-time interval that the ISO has established a Scarcity Reserve Requirement(s) in the Real-Time Market, other than a Scarcity Reserve Requirement for which the pricing rules established in Section 15.4.6.1.1(a)(i) of this Rate Schedule apply, the applicable Operating Reserves demand curve for total 30-Minute Reserves shall be as follows: For quantities of Operating Reserves meeting the total 30-Minute Reserves locational requirement target level plus the applicable Scarcity Reserve Requirement(s) ("adjusted NYCA target level") that are less than or equal to the adjusted NYCA target level minus 955 MW, the price on the total 30-Minute Reserves demand curve shall be $750/MW.

For quantities of Operating Reserves meeting the adjusted NYCA target level that are less than or equal to the adjusted NYCA target level but that exceed the adjusted NYCA target level minus 955 MW, the price on the total 30-Minute Reserves demand curve shall be $500/MW. For all other quantities, the price on the total 30-Minute Reserves demand curve shall be $0/MW. However, the ISO will not schedule more total 30-Minute Reserves than the level defined by the total 30-Minute Reserves locational requirement plus the applicable Scarcity Reserve Requirement(s) for that interval.

(j) Eastern, Southeastern or Long Island 30-Minute Reserves: For quantities of Operating Reserves meeting the Eastern, Southeastern or Long Island 30-Minute Reserves requirement that are less than or equal to the target level for that locational requirement, the price on the Eastern, Southeastern or Long Island 30-Minute Reserves demand curve shall be $25/MW. For all other quantities, the price on the Eastern, Southeastern or Long Island 30-Minute Reserves demand curve shall be $0/MW.

During each real-time interval that the ISO has established a Scarcity Reserve Requirement in the Real-Time Market for which the pricing rules established in Section 15.4.6.1.1(a)(ii) of this Rate Schedule apply, the applicable Operating Reserves demand curve for Eastern, Southeastern or Long Island 30-Minute Reserves shall be as follows: For quantities of Operating Reserves meeting the Eastern, Southeastern or Long Island 30-Minute Reserves locational requirement target level plus the Scarcity Reserve Requirement (“Eastern scarcity target level”) that are less than or equal to the Eastern scarcity target level minus an amount equal to the Eastern, Southeastern or Long Island 30-Minute Reserves locational requirement target, the price on the Eastern, Southeastern or Long Island 30-Minute Reserves demand curve shall be $500/MW. For the quantities of Operating Reserves meeting the Eastern scarcity target level that are less than or equal to the Eastern scarcity target level but exceed the Eastern scarcity target level minus an amount equal to the Eastern, Southeastern or Long Island 30-Minute Reserves locational requirement target level, the price on the Eastern, Southeastern or Long Island 30-Minute Reserves demand curve shall be $25/MW. For all other quantities, the price on the Eastern, Southeastern or Long Island 30-Minute Reserves demand curve shall be $0/MW.

During each real-time interval that the ISO has established a Scarcity Reserve Requirement(s) in the Real-Time Market for which all the Load Zones encompassed by such Scarcity Reserve Requirement belong to the East of Central-East reserve region, other than a Scarcity Reserve Requirement for which the pricing rules established in Section 15.4.6.1.1(a)(ii) of this Rate Schedule apply, the applicable Operating Reserves demand curve for Eastern, Southeastern or Long Island 30-Minute Reserves shall be as follows: For quantities of Operating Reserves meeting the Eastern, Southeastern or Long Island 30-Minute Reserves locational requirement target level plus the applicable Scarcity Reserve Requirement(s) ("adjusted Eastern target level") that are less than or equal to the adjusted Eastern target level, the price on the Eastern, Southeastern or Long Island 30-Minute Reserves demand curve shall be $25/MW. For all other quantities, the price on the Eastern, Southeastern or Long Island 30-Minute Reserves demand curve shall be $0/MW.

(k) Southeastern or Long Island 30-Minute Reserves: For quantities of Operating Reserves meeting the Southeastern or Long Island 30-Minute Reserves requirement that are less than or equal to the target level for that locational requirement, the price on the Southeastern or Long Island 30-Minute Reserves demand curve shall be $500/MW. For all other quantities, the price on the Southeastern or Long Island 30-Minute Reserves demand curve shall be $0/MW. During each real-time interval that the ISO has established a Scarcity Reserve Requirement in the Real-Time Market for which the pricing rules established in Section 15.4.6.1.1(a)(iii) of this Rate Schedule apply, the applicable Operating Reserves demand curve for Southeastern or Long Island 30-Minute Reserves shall be as follows: For quantities of Operating Reserves meeting the Southeastern or Long Island 30-Minute Reserves locational requirement target level plus the Scarcity Reserve Requirement ("Southeastern scarcity target level") that are less than or equal to the Southeastern scarcity target level, the price on the Southeastern or Long Island 30-Minute Reserves demand curve shall be $500/MW. For all other quantities, the price on the Southeastern or Long Island 30-Minute Reserves demand curve shall be $0/MW.

During each real-time interval that the ISO has established a Scarcity Reserve Requirement(s) in the Real-Time Market for which all the Load Zones encompassed by such Scarcity Reserve Requirement belong to the Southeastern New York reserve region, other than a Scarcity Reserve Requirement for which the pricing rules established in Section 15.4.6.1.1(a)(iii) of this Rate Schedule apply, the applicable Operating Reserves demand curve for Southeastern or Long Island 30-Minute Reserves shall be as follows: For quantities of Operating Reserves meeting the Southeastern or Long Island 30-Minute Reserves locational requirement target level plus the applicable Scarcity Reserve Requirement(s) ("adjusted Southeastern target level") that are less than or equal to the adjusted Southeastern target level, the price on the Southeastern or Long Island 30-Minute Reserves demand curve shall be \$500/MW. For all other quantities, the price on the Southeastern or Long Island 30-Minute Reserves demand curve shall be \$0/MW.

(l) Long Island 30-Minute Reserves: For quantities of Operating Reserves meeting the Long Island 30-Minute Reserves requirement that are less than or equal to the target level for that locational requirement, the price on the Long Island 30-Minute Reserves demand curve shall be \$25/MW. For all other quantities, the price on the Long Island 30-Minute Reserves demand curve shall be \$0/MW. During each real-time interval that the ISO has established a Scarcity Reserve Requirement in the Real-Time Market for which the pricing rules established in Section 15.4.6.1.1(a)(iv) of this Rate Schedule apply, the applicable Operating Reserves demand curve for Long Island 30-Minute Reserves shall be as follows: For quantities of Operating Reserves meeting the Long Island 30-Minute Reserves locational requirement target level plus the Scarcity Reserve Requirement ("Long Island scarcity target level") that are less than or equal to the Long Island scarcity target level minus an amount equal to the Long Island 30-

Minute Reserves locational requirement target, the price on the Long Island 30-Minute Reserves demand curve shall be $500/MW. For the quantities of Operating Reserves meeting the Long Island scarcity target level that are less than or equal to the Long Island scarcity target level but exceed the Long Island scarcity target level minus an amount equal to the Long Island 30-Minute Reserves locational requirement target level, the price on the Long Island 30-Minute Reserves demand curve shall be $25/MW. For all other quantities, the price on the Long Island 30-Minute Reserves demand curve shall be $0/MW.

The ISO will procure additional Operating Reserves to meet each Scarcity Reserve Requirement established by the ISO in the Real-Time Market for which the pricing rules established in Section 15.4.6.1.1(b) of this Rate Schedule apply. The Scarcity Reserve Demand Curve for each real-time interval in which the ISO has established such a Scarcity Reserve Requirement shall be defined as follows: For quantities of Operating Reserves meeting the Scarcity Reserve Requirement that are less than or equal to the Scarcity Reserve Requirement, the price on the Scarcity Reserve Demand Curve shall be $500/MW. For all other quantities, the price on the Scarcity Reserve Demand Curve shall be $0/MW.

In order to respond to operational or reliability problems that arise in real-time, the ISO may procure any Operating Reserve product at a quantity and/or price point different than those specified above. The ISO shall post a notice of any such purchase as soon as reasonably possible and shall report on the reasons for such purchases at the next meeting of its Business Issues Committee. The ISO shall also immediately initiate an investigation to determine whether it is necessary to modify the quantity and price points specified above to avoid future operational or reliability problems. The ISO will consult with its Market Monitoring Unit when it conducts this investigation.

If the ISO determines that it is necessary to modify the quantity and/or price points specified above in order to avoid future operational or reliability problems it may temporarily modify them for a period of up to ninety days. If circumstances reasonably allow, the ISO will consult with its Market Monitoring Unit, the Business Issues Committee, the Commission, and the PSC before implementing any such modification. In all circumstances, the ISO will consult with those entities as soon as reasonably possible after implementing a temporary modification.

Not later than 90 days after the implementation of the Operating Reserves Demand Curves the ISO, in consultation with its Market Advisor, shall conduct an initial review of them in accordance with the ISO Procedures. The scope of the review shall include, but not be limited to, an analysis of whether any Operating Reserve Demand Curve should be adjusted upward or downward in order to optimize the economic efficiency of any, or all, of the ISO Administered Markets. The ISO and the Market Advisor shall perform additional quarterly reviews, subject to the same scope requirement, during the remainder of the first year that this Section 15.4.7 is in effect. After the first year, the ISO shall perform periodic reviews, subject to the same scope requirement, and the Market Monitoring Unit shall be given the opportunity to review and comment on the ISO's periodic reviews of the Operating Reserve Demand Curves and Scarcity Reserve Demand Curve.

The responsibilities of the Market Monitoring Unit that are addressed in the above section of Rate Schedule 4 to the Services Tariff are also addressed in Section 30.4.6.4.2 of Attachment O.

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15.4.8 Self-Supply

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

Alternatively, Customers, including LSEs, may enter into Day-Ahead Bilateral financial Transactions, *e.g.*, contracts-for-differences, in order to hedge against price volatility in the Operating Reserves markets.

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15.5 Rate Schedule 5 - Payments and Charges for Black Start and System Restoration Services

Black start and system restoration services ("Restoration Services") are provided under the ISO's black start and system restoration plan ("ISO Plan") or an individual Transmission Owner's black start and system restoration plan for its Transmission District by generating units that are capable of starting without an outside electrical supply or are otherwise integral to the restoration of the NYS Transmission System after an outage. This Rate Schedule establishes the terms under which a Generator shall provide, and be paid by the ISO for providing, Restoration Services under the ISO Plan or an individual Transmission Owner's plan for its Transmission District. This Rate Schedule also establishes the terms under which the ISO shall recover the costs of Restoration Services payments from Customers. Provisions specific to the Consolidated Edison Company of New York, Inc. ("Consolidated Edison") black start and system restoration plan ("Consolidated Edison Plan") are set forth in Section 15.5.4.

15.5.1 Requirements

The ISO shall develop and periodically review the ISO Plan. The ISO may amend the ISO Plan and may solicit offers for additional resources if it determines that additional Restoration Services are needed. The ISO shall establish procedures for acquiring Restoration Services and requiring that the selected Generators test their units providing Restoration Services ("Black Start Capability Test"). The ISO shall make Restoration Services payments only to those selected Generators that have appropriate equipment installed and available for service at the request of the ISO.

A Transmission Owner with a Transmission District shall develop and periodically review its black start and system restoration plan. Such Transmission Owner shall designate generating units with the capability to provide Restoration Services to be included in its plan if it determines that the Restoration Services are needed. The ISO will make payments for such local Restoration Services to the Generators that provide them under the terms of this Rate Schedule. Generators that are obligated to provide Restoration Services as a result of divestiture contract agreements will not receive Restoration Services payments from the ISO for those services if they are already compensated as part of those divestiture contracts. Customers in the local Transmission Owner service territories will be charged for those services by the ISO under the terms of this Rate Schedule. Customers may not Self-Supply Restoration Services.

15.5.2 Payments to Generators for Provision of Restoration Services Under the ISO Plan and Transmission Owners' Plans, Excluding the Consolidated Edison Plan

By May 1st of each year, Generators selected to provide Restoration Services under the ISO Plan and under the plans developed by individual Transmission Owners with a Transmission District, except for under the Consolidated Edison Plan, must provide the following cost information to the ISO based upon FERC Form No. 1 or equivalent data:

- Capital and fixed operation and maintenance costs associated with only that equipment which provides Restoration Services capability;
- Annual costs associated with training operators in Restoration Services; and
- Annual costs associated with Black Start Capability Tests in accordance with the ISO Plan or the plan of an individual Transmission Owner.

Each Billing Period, the ISO shall pay each Generator on the basis of its costs filed with the ISO. The daily rate for Restoration Services payments will be determined by dividing the Generator's annual cost by the number of days in the year from May 1st through April 30th of the following year.

Generators that provide Restoration Services shall conduct Black Start Capability Tests that are deemed necessary and appropriate for providers of these services under the ISO

Procedures or local Transmission Owner procedures, as applicable. Any Generator that is awarded Restoration Services payments and fails a Black Start Capability Test shall forfeit all payments for such services since its last successful test. Payments to that Generator shall resume upon its successful completion of the test.

15.5.3 Charges to Support Payments to Generators Under the ISO Plan and Individual Transmission Owners' Plans, Excluding the Consolidated Edison Plan.

Each Billing Period, the ISO shall charge, and each Customer shall pay based on its supply of Load that is *not* used to supply Station Power as a third-party provider under Part 5 of the ISO OATT, a charge for the recovery of the costs of the ISO's payments to Generators providing Restoration Services under the ISO Plan. The charge shall be equal to: (A) the product of: (i) the Customer's share of Load in the NYCA that is *not* used to supply Station Power as a third-party provider for each hour in the Billing Period, and (ii) the ISO's total payments to Generators providing Restoration Services under the ISO Plan under Section 15.5.2 to this Rate Schedule for the Billing Period, divided by the total number of hours in the Billing Period, (B) summed for all hours in the Billing Period.

Each Billing Period, the ISO shall charge, and each Customer shall pay based on its supply of Load that is used to supply Station Power as a third-party provider under Part 5 of the ISO OATT, a charge for the recovery of the costs of the ISO's payments to Generators providing Restoration Services under the ISO Plan. The charge shall be equal to: (A) the product of: (i) the Customer's share of Load in the NYCA that is used to supply Station Power as a third-party provider for each day in the Billing Period, and (ii) the ISO's total payments to Generators providing Restoration Services under the ISO Plan under Section 15.5.2 to this Rate Schedule for the Billing Period, divided by the total number of days in the Billing Period, (B) summed for all days in the Billing Period. The ISO shall credit these daily charge amounts to Customers based on their share of the Load in the NYCA that is not used to supply Station Power as a third-party provider for that day. The ISO shall sum these daily credits for all days in the Billing Period.

A Customer will be responsible for the following additional charge if the Transmission Owner in whose Transmission District the Customer is located maintains a Restoration Services plan, except with respect to the Consolidated Edison Plan, the cost recovery requirements of which are set forth in Section 15.5.4.2 to this Rate Schedule. Each Billing Period, the ISO shall charge, and each Customer in the local Transmission Owner's Transmission District shall pay, a charge for the recovery of the costs of the ISO's payments to Generators providing Restoration Services under the Transmission Owner's local Restoration Services plan. This charge shall be equal to: (A) the product of: (i) the Customer's share of Load in the Transmission Owner's Transmission District for each hour in the Billing Period, and (ii) the ISO's total payments to Generators providing Restoration Services under the Transmission Owner's Restoration Services plan under Section 15.5.2 to this Rate Schedule for the Billing Period, divided by the total number of hours in the Billing Period, (B) summed for all hours in the Billing Period.

15.5.4 Payments to Generators Providing Restoration Services Under the Consolidated Edison Plan and Recovery of Associated Costs

A Generator that provides Restoration Services under the Consolidated Edison Plan shall provide, and be paid for providing, Restoration Services under the terms set forth in Section 15.5.4.1 and Appendix I to this Rate Schedule. If Consolidated Edison determines that additional Restoration Services are needed, it may from time to time designate for inclusion in the Consolidated Edison Plan: (i) an existing generating unit that is capable of providing Restoration Services but that is not currently doing so, or (ii) a generating unit for which the

Generator has provided notice to withdraw from the Consolidated Edison Plan pursuant to Section 15.5.4.1.1. A generating unit designated by Consolidated Edison may elect to participate in the Consolidated Edison Plan; otherwise it shall be required to participate in the Consolidated Edison Plan unless the ISO determines that: (i) the generating unit would not provide a material benefit to system restoration in Zone J, or (ii) the Generator shows good cause that it would be unduly burdensome or unreasonable to require it to provide Restoration Services from the designated generating unit.

The provision of Restoration Services will be deemed to provide a material benefit to system restoration in Zone J if, among other things, it would materially improve the speed, adequacy, or flexibility of the Consolidated Edison Plan for restoring electric service in Zone J in a safe, orderly, and prompt manner following a major system disturbance.

To facilitate the ISO's determination regarding material benefit, Consolidated Edison shall provide a study and/or other documentation, performed at its own expense, supporting the conclusion that the designated generating unit would provide a material benefit for system restoration in Zone J. Consolidated Edison's documentation must: (i) include its assessment of the adequacy of resources already committed to provide Restoration Services under the Consolidated Edison Plan and the need for additional resources, (ii) describe the manner in which the designated generating unit would provide a material benefit for system restoration in Zone J, and (iii) summarize alternative solutions evaluated, if applicable, and indicate whether other generating units would provide the particular material benefit identified. Consolidated Edison shall provide its documentation to the ISO and the relevant Generator, subject to appropriate confidentiality protections. Upon request, Consolidated Edison shall provide the documentation to other parties that have a direct interest in this matter, subject to appropriate confidentiality protections.

If the Generator asserts that good cause exists for not requiring its generating unit to participate in the Consolidated Edison Plan, it must seek an exemption from the ISO. The Generator shall provide a study or other documentation demonstrating the engineering, technical, financial, environmental, and/or other reasons that provision or continued provision of Restoration Services by the designated generating unit would be unduly burdensome or unreasonable. The Generator shall provide its documentation to the ISO and Consolidated Edison, subject to appropriate confidentiality protections. The Generator may provide the documentation to other parties that have a direct interest in this matter as well, subject to appropriate confidentiality protections. In making its determination, the ISO may rely on the supporting documentation provided by the Generator and Consolidated Edison, along with any information developed by the ISO.

If the ISO determines that good cause exists to grant a requested exemption, the designated generating unit will not be required to participate in the Consolidated Edison Plan. Otherwise, the designated generating unit will be required to participate in the Consolidated Edison Plan and will be assigned by the ISO to a Commitment Group under Section 15.5.4.1.1. The ISO shall inform NYSRC of a designated generating unit's request for an exemption and the ISO's determination under this Section 15.5.4.

A Generator's unit that is designated by Consolidated Edison to participate in the Consolidated Edison Plan, and is not granted an exemption under this Section 15.5.4 shall provide, and be paid for providing, Restoration Services under the terms set forth in Section 15.5.4.1 and AppendixI to this Rate Schedule.

The ISO shall recover the costs of the payments established in Section 15.5.4.1 from Customers in the Consolidated Edison Transmission District under the terms set forth in Section 15.5.4.2.

Within thirty (30) days of receipt of an updated Consolidated Edison Plan, including changes to unit designations as described in this section, the ISO will file a copy with FERC on an informational basis with a non-public Critical Energy Infrastructure Information designation.

15.5.4.1 Payments to Generators that Provide Restoration Services Under the Consolidated Edison Plan

15.5.4.1.1 Commitment Requirements for Restoration Services

Each generating unit committed to provide Restoration Services under the Consolidated Edison Plan before November 1, 2012, was included in one of three groups ("Commitment Groups") with the following initial commitment periods:

Commitment Group 1: November 1, 2012, through April 30, 2015.

Commitment Group 2: November 1, 2012, through April 30, 2016.

Commitment Group 3: November 1, 2012, through April 30, 2017.

The ISO shall assign a generating unit subsequently designated to provide Restoration Services under the Consolidated Edison Plan to one of these Commitment Groups.

At the conclusion of each commitment period, a generating unit shall begin a new three (3) year commitment period to provide Restoration Services under the Consolidated Edison Plan; provided, however, that the unit shall not begin a new commitment period if the Generator or Consolidated Edison provides the ISO with notice at least two years prior to the conclusion of the previous commitment period that the unit will no longer be part of the Consolidated Edison Plan following the conclusion of that commitment period.

Notwithstanding the foregoing, a unit previously designated under Section 15.5.4 shall be required to begin a new commitment period if: (i) Consolidated Edison provides the ISO and the Generator with notice at least one year prior to the conclusion of the previous commitment period that the unit continues to be required to provide a material benefit to system restoration in Zone J, (ii) and the ISO determines that the unit should continue to provide service in accordance with the designation requirements in Section 15.5.4, including the opportunity for the Generator to request an exemption.

Consolidated Edison shall not remove from the Consolidated Edison Plan a new or repowered unit that was required to provide Restoration Services in the Consolidated Edison Plan pursuant to Section 30.2.5 of Attachment X to the ISO OATT before the Generator recovers the incremental capital costs it incurred in installing the Restoration Services capability for its unit. The Generator shall be deemed to have recovered these costs: (a) twenty-five years from the start of the unit's provision of Restoration Services if the Generator is taking payment pursuant to Section 15.5.4.1.3.1 to this Rate Schedule, or (b) over the period set forth in the Generator's unit-specific rate approved by FERC pursuant to Section 15.5.4.1.3.2 to this Rate Schedule. If a Generator withdraws its unit from the Consolidated Edison Plan before the completion of this time period, it will forfeit its entitlement to recover its incremental capital costs.

If a Generator withdraws a unit from the ISO's energy and capacity markets, the unit may cease its provision of Restoration Services at the same time without completing its commitment period. If the Generator returns the unit to the ISO's energy and capacity markets within three years of its withdrawal, the unit shall be required to provide Restoration Services for that portion of its commitment period that it had not completed.

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15.5.4.1.2 Generator Testing and Training Requirements

A Generator shall conduct an annual Black Start Capability Test of each unit committed to provide Restoration Services under the Consolidated Edison Plan in accordance with the test protocols required by the Reliability Rules and applicable reliability standards and set forth in ISO Procedures. A Generator shall also identify its unit's critical Restoration Services equipment, maintain this equipment and perform tests to verify the condition of this critical equipment in accordance with good utility practice. Upon the performance of a Black Start Capability Test for its unit, the Generator shall submit a certification to the ISO each year – in the form provided in Appendix II to this Rate Schedule – indicating whether its unit has successfully completed its annual Black Start Capability Test and certifying that it maintains and tests the unit's critical Restoration Services equipment in accordance with good utility practice. The Generator shall also ensure that all appropriate personnel are trained in Restoration Services operations.

15.5.4.1.3 Payments to Generators for Providing Restoration Services Under the Consolidated Edison Plan

15.5.4.1.3.1 Standard Compensation

Except as set forth in Section 15.5.4.1.3.2 to this Rate Schedule, the ISO shall pay a Generator each Billing Period the pro rata share of the sum of the annual payment amounts for the provision of Restoration Services under the Consolidated Edison Plan at each of the Generator's facilities, as determined for each facility as follows.

The ISO shall calculate the annual Restoration Services payment amount for each Generator's facility for the compensation period of May 1 of each year through the following April 30; *provided, however*, the ISO shall recalculate the annual Restoration Services payment amount if, during the May 1 through April 30 compensation period, one of the Generator's units withdraws from the Consolidated Edison Plan pursuant to Section 15.5.4.1.1 to this Rate Schedule or fails a Black Start Capability Test pursuant to Section 15.5.4.1.3.4 to this Rate Schedule.

The annual Restoration Services payment amount for each Generator's facility shall be equal to the sum of the annual payment amounts, calculated according to the following formula, for: (i) each unit at a Generator's facility providing Restoration Services under the Consolidated Edison Plan that is the sole user of equipment necessary to black start the unit and is not designated with other units as a group by the ISO ("Sole Black Start Unit"), and (ii) each group of units at the Generator's facility providing Restoration Services under the Consolidated Edison Plan that share the equipment necessary to black start the units or are otherwise designated as a group by the ISO ("Black Start Unit Group"). The ISO shall designate a Generator's unit as a Sole Black Start Unit or as part of a Black Start Unit Group at the start of the unit's commitment period, and this designation shall not be subject to change for the duration of the unit's commitment period.

$RSPayment_{AnnBSU} =$

$$ActRSUnits_{BSU} \text{ x } \left(\frac{RSSlCap_{Ann} + RSSlO\&M_{Ann} + RSAddCap_{Ann} + RSAddO\&M_{Ann}}{DesRSUnits_{BSU}} \right)$$

Where:

BSU = The Sole Black Start Unit or the Black Start Unit Group.

$RSPayment_{AnnBSU}$ = The annual amount, in $, that the ISO shall pay a Generator for the Sole Black Start Unit or the Black Start Unit Group providing Restoration Services under the Consolidated Edison Plan.

$DesRSUnits_{BSU}$ = The number of units in the Sole Black Start Unit or the Black Start Unit Group designated by Consolidated Edison as participants in the Consolidated Edison Plan.

$ActRSUnits_{BSU}$ = The number of units in the Sole Black Start Units or the Black Start Unit Group actually participating in the Consolidated Edison Plan, which shall not include any unit designated by Consolidated Edison as a participant in the Consolidated Edison Plan that has withdrawn from the plan pursuant to Section 15.5.4.1.1 to this Rate Schedule or has failed a Black Start Capability Test pursuant to Section 15.5.4.1.3.4 to this Rate Schedule.

$RSSlCap_{Ann}$ = The station-level capital payment amount, in \$, for the Sole Black Start Unit or for one unit of the Black Start Unit Group, as specified in the "Station-level" column of Table A, below, on the basis of that unit's size.

$RSSlO\&M_{Ann}$ = The station-level operating and maintenance amount, in \$, for the Sole Black Start Unit or for one unit of the Black Start Unit Group, as specified in the "Station-level" column of Table B, below, on the basis of the unit's size.

$RSAddCap_{Ann}$ = The sum of the incremental capital payment amounts, in \$, for the remaining units in the Black Start Unit Group, as specified in the "Additional Resource" column of Table A, below, on the basis of the remaining units' sizes.

$RSAddO\&M_{Ann}$ = The sum of the incremental operating and maintenance payment amounts, in \$, for the remaining units in the Black Start Unit Group, as specified in the "Additional Resource" column in Table B, below, on the basis of the remaining units' sizes.

Table A - Restoration Services Capital Payments

Resource Type	**Station-level Capital Payment**	**Additional Resource Capital Payment**
MVA ≤ 10	$21,770	$10,880
10 < MVA ≤ 60	$214,570	$10,880
60 < MVA ≤ 90	$248,460	$10,880
90 < MVA ≤ 300, Small Starting Requirement	$414,980	$10,880
90 < MVA ≤ 300, Medium Starting Requirement	$957,920	$10,880
90 < MVA ≤ 300, Large Starting Requirement	$1,785,080	$10,880
300 < MVA, Large Starting Requirement	$1,833,750	$32,650

Table B - Restoration Services O&M Payments

Resource Type	Station-level O&M Payment	Additional Resource O&M Payment
MVA ≤ 10	$22,335	$6,040
10 < MVA ≤ 60	$42,295	$8,200
60 < MVA ≤ 90	$49,850	$10,140
90 < MVA ≤ 300, Small Starting Requirement	$118,255	$33,665
90 < MVA ≤ 300, Medium Starting Requirement	$252,265	$65,600
90 < MVA ≤ 300, Large Starting Requirement	$388,865	$65,820
300 < MVA, Large Starting Requirement	$414,540	$77,685

The figures in Tables A and B are determined as of 2011. The ISO shall adjust these figures annually using the "Gas Turbogenerators" subcategory of the "Other Production Plant" category of the Handy Whitman Index for the North Atlantic Region.

15.5.4.1.3.2 Unit-Specific Compensation

A Generator shall be entitled to recover through this ISO Services Tariff the actual, incremental cost of its unit's or units' provision of Restoration Services under the Consolidated Edison Plan. If the Generator determines that its actual, incremental cost of providing Restoration Services to the ISO from its unit(s) exceeds the payment amount determined under Section 15.5.4.1.3.1 to this Rate Schedule, the Generator shall submit to the ISO actual incremental cost documentation showing: (1) that the actual, incremental costs are reasonably and prudently incurred, (2) that the actual incremental costs are incurred solely for the purpose of providing Restoration Services, and (3) that the actual incremental costs exceed the payment amount determined under Section 15.5.4.1.3.1 to this Rate Schedule. Within thirty (30) days of receipt of all necessary documentation, or longer if the parties agree, the ISO will file at FERC, jointly with the Generator, the information provided by the Generator along with the proposed tariff appendix. The Generator will retain the burden to show that its unit(s)-specific rate request meets the cost showing requirements outlined in this section. NYISO may subsequently comment on the substance of the proposed filing during the FERC noticed comment period. Upon approval by FERC, the Generator's unit(s)-specific rate shall be included as an appendix to this Rate Schedule. In such case, the ISO shall pay a Generator each Billing Period the pro rata share of the FERC-approved annual rate for its unit(s), except as set forth in Section 15.5.4.1.3.4 to this Rate Schedule. The ISO shall recover the costs of these payments from Customers in the Consolidated Edison Transmission District under Section 15.5.4.2 to this Rate Schedule.

15.5.4.1.3.3 Eligibility for Additional Cost Recovery

The ISO shall reimburse Generators for equipment damage if the ISO reasonably finds: (1) the damage resulted from operating such equipment in response to operational orders from the ISO, or Consolidated Edison, pursuant to the ISO Tariffs, (2) that reasonably available and customary insurance was not available for the damages incurred, and (3) the damage would not have occurred but for the Generator's provision of Restoration Services. The burden of making such showings shall be upon the Generator.

The payments for each Billing Period shall also include compensation for legitimate, verifiable, and adequately documented costs incurred solely as a result of a Generator's compliance with NERC critical infrastructure protection ("CIP") reliability standards applicable to the provision of Restoration Services, *i.e.*, a CIP cost that would not have been incurred if it were not providing Restoration Services. The Generator shall provide such invoices to the ISO, which will review and determine if compensation is appropriate.

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15.5.4.1.3.4 Forfeiture of Payments As a Result of Failed Black Start Capability Tests

If a Generator's unit fails a Black Start Capability Test, the Generator shall forfeit all Restoration Service payments for that unit under Sections 15.5.4.1.3.1 and 15.5.4.1.3.2 from the date of the failed test; provided, however, that if the Generator's unit successfully completes the Black Start Capability Test within thirty days of the failed test, the Generator shall not forfeit its payments. This thirty-day period may be extended if agreed upon by the ISO, the Generator, and Consolidated Edison. If the Generator does not successfully complete its Black Start Capability Test within this thirty day, or extended, period and successfully completes the test at a later date, it shall receive its Restoration Services payments only from the date of the later, successful test going forward.

15.5.4.2 Charges to Support Payments to Generators Under the Consolidated Edison Plan

Each Billing Period, the ISO shall charge, and each Customer in the Consolidated Edison Transmission District shall pay based on its supply of Load in that Transmission District that is *not* used to supply Station Power as a third-party provider under Part 5 of the ISO OATT, a charge for the recovery of the ISO's payments to Generators providing Restoration Services under the Consolidated Edison Plan under Section 15.5.4.1 to this Rate Schedule. This charge shall be equal to: (A) the product of : (i) the Customer's share of Load in the Consolidated Edison Transmission District that is not used to supply Station Power as a third-party provided for each hour in the Billing Period, and (ii) the ISO's total payments to Generators for Restoration Services under the Consolidated Edison Restoration Plan under Sections 15.5.4.1 for the Billing Period, divided by the total number of hours in the Billing Period, (B) summed for all hours in the Billing Period.

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Each Billing Period, the ISO shall charge, and each Customer in the Consolidated Edison Transmission District shall pay based on its supply of Load in that Transmission District that is used to supply Station Power as a third-party provider under Part 5 of the ISO OATT, a charge for the recovery of the ISO's payments to Generators providing Restoration Services under the Consolidated Edison Plan under Section 15.5.4.1 to this Rate Schedule. This charge shall be equal to: (A) the product of: (i) the Customer's share of Load in the Consolidated Edison Transmission District that is used to supply Station Power as a third-party provided for each day in the Billing Period, and (ii) the ISO's total payments to Generators for Restoration Services under the Consolidated Edison Restoration Plan under Section 15.5.4.1 for the Billing Period, divided by the total number of days in the Billing Period, (B) summed for all days in the Billing Period. The ISO shall credit these daily charge amounts to Customers based on their share of Load in the NYCA that is not used to supply Station Power as a third-party provider for that day. The ISO shall sum these daily credits for all days in the Billing Period.

Rate Schedule 5. Appendix I
Restoration Services Certification Form

[Name of Generator] hereby certifies that the **[name/location of unit]** performed a Black Start Capability Test on **[date]** and **[successfully completed/did not complete]** this test in accordance with the applicable ISO Procedures.

[Name of Generator] further certifies that it has identified a list of critical components in its units providing Restoration Services (e.g., batteries, diesel back-up generators, inverters etc.), maintains such critical components, and has performed tests to verify the condition of these critical components in accordance with good utility practice.

____

Signature of Officer

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15.6 Rate Schedule 6 - Quick Start Reserves

This Rate Schedule applies to the scheduling and payment mechanisms for Quick Start Reserves.

15.6.1 Qualification to Provide Quick Start Reserves

15.6.1.1 A Supplier may offer Quick Start Reserves from one or more blocks of generator units to the Transmission Owner to which the block of generator units is interconnected if the block of generator units is (i) qualified to provide 30-Minute Reserves, and (ii) capable of being set to Quick Start Mode.

15.6.1.2 A Supplier intending to offer Quick Start Reserves shall undertake a test scheduled pursuant to the ISO Procedures for Installed Capacity Suppliers qualifying to sell Installed Capacity in the NYCA to determine the DMNC of the Supplier's block of generator units. The Supplier shall, while undertaking the DMNC test in Quick Start Mode, make record of and notify, for information purposes, the Transmission Owner in the Supplier's Transmission District and the ISO of (i) the output level in MWs that the block of generator units produced at ten (10) minutes following start-up; and (ii) the output level in MWs that the block of generator units produced at fifteen (15) minutes following start-up. Delivery of this information to the Transmission Owner in the Supplier's Transmission District and the ISO shall constitute and be deemed to be a standing offer to provide Quick Start Reserves pursuant to Section 15.6.2 of this Rate Schedule until (i) the Supplier performs another DMNC test and provides the information required pursuant to this Section 15.6.1.2 to the ISO and the

Transmission Owner, (ii) thirty (30) days after providing a notice to the ISO and the Transmission Owner that it no longer offers Quick Start Reserves from any one or more blocks of generator units, provided that the supplier is not otherwise required to provide Quick Start Reserves, or (iii) the Supplier is not paid for Quick Start Reserves as provided herein.

15.6.1.3 A Supplier shall maintain each block of generator units for which Quick Start Reserves are offered in good working order to provide Energy in an amount at its temperature-adjusted DMNC within fifteen (15) minutes of remote start-up.

15.6.1.4 A Transmission Owner receiving the information specified in Section 15.6.1.2 of this Rate Schedule shall confirm to the ISO and the Supplier whether the Transmission Owner has the ability to remotely start up a block of generator units that the Supplier has offered for Quick Start Reserves. This confirmation informs the Supplier that the Transmission Owner or the ISO may elect to purchase Quick Start Reserves from each block of generator units that the Supplier has offered for Quick Start Reserves.

15.6.2 Purchase and Selection of Quick Start Reserves and Associated Duties

15.6.2.1 When a Transmission Owner has issued confirmation pursuant to Section 15.6.1.4 of this Rate Schedule and requires Quick Start Reserves, the Transmission Owner may purchase Quick Start Reserves from the Supplier by telephonic request; provided, however, that the Transmission Owner shall not purchase Quick Start Reserves unless the Transmission Owner has received the ISO's concurrence with the proposed purchase of Quick Start Reserves. The telephonic request shall specify the starting time and either the number of MWs of

Quick Start Reserves required or the block of generator units from which the Supplier is to sell Quick Start Reserves. In addition, the telephonic request shall, if available and for information purposes only, specify the estimated number of hours for which the Transmission Owner intends to purchase Quick Start Reserves. The Transmission Owner shall give written notice by electronic mail (or fax if electronic mail is not available) to each of the Supplier and the ISO of the telephonic request within ten (10) minutes of making the telephonic request, and the written notice by electronic mail or fax shall provide the same information specified in the Transmission Owner's telephonic request and shall also provide the time of the telephonic request. If the Supplier has not received such written notice or disagrees with its contents, the Supplier shall give notice by electronic mail (or fax if electronic mail is not available) to each of the ISO and the Transmission Owner confirming the telephonic request, and the notice by electronic mail or fax shall provide the same information specified in the Transmission Owner's telephonic request and shall also provide the time of the telephonic request.

15.6.2.2 A Transmission Owner shall stop purchasing some or all the Quick Start Reserves from a Supplier upon giving telephonic notice to the Supplier that the Transmission Owner no longer requires some or all the Quick Start Reserves; provided, however, that the Transmission Owner shall not stop the purchase of Quick Start Reserves without the ISO's concurrence. The Transmission Owner shall give written notice by electronic mail (or fax if electronic mail is not available) to each of the Supplier and the ISO of the telephonic notice within ten

(10) minutes of providing the telephonic notice, and the written notice by electronic mail or fax shall provide the time of the telephonic notice. If the Supplier has not received such written notice or disagrees with its contents, the Supplier shall give notice by electronic mail (or fax if electronic mail is not available) to each of the ISO and the Transmission Owner of the telephonic notice, and the notice by electronic mail or fax shall provide the same information specified in the Transmission Owner's telephonic notice and shall also provide the time of the telephonic notice.

15.6.2.3 The ISO shall maintain complete and accurate records of all notices received by electronic mail or fax pursuant to Sections 15.6.2.1 and 15.6.2.2 of this Rate Schedule.

15.6.2.4 A Supplier offering Quick Start Reserves that receives a telephonic request to purchase or to select Quick Start Reserves shall set one or more blocks of generator units to Quick Start Mode as requested within ten (10) minutes of the telephonic request; provided, however, that the Supplier shall have no obligation to set a block of generator units to or to maintain a block of generator units in Quick Start Mode during (i) periods of forced outage, (ii) maintenance outages that are approved in advance pursuant to the ISO Services Tariff, or (iii) any period when the requested block of generator units is producing Energy.

15.6.2.5 During any period when the Transmission Owner has not purchased Quick Start Reserves from an offered block of generator units, the Supplier shall not be required to set the block of generator units to or to maintain the block of generator units in Quick Start Mode, subject to the requirement that the Supplier set the block of generator units to Quick Start Mode within ten (10) minutes of a request pursuant to Section 15.6.2.1 of this Rate Schedule.

15.6.2.6 A Supplier offering Quick Start Reserves shall maintain Hour-Ahead Bids for Energy at all times for each of the Supplier's block of generator units comprising the offered, purchased, or selected Quick Start Reserves, and shall maintain these Bids in the Real-Time Market.

15.6.3 Duty to Produce Energy

15.6.3.1 A Transmission Owner may remotely start up any block of generator units that is providing Quick Start Reserves. Upon remote start-up, the Transmission Owner shall give notice to the ISO that the block of generator units have been started up out of merit for local reliability. A Transmission Owner may dispatch off a block of generator units started up out of merit when Energy from the block of generator units is no longer required for local reliability, subject to any minimum run time of the block of generator units; provided, however, that the Transmission Owner shall not dispatch off the block of generator units without the ISO's concurrence.

15.6.3.2 During each period when a Transmission Owner has purchased Quick Start Reserves, the Supplier shall respond to each remote start-up order from the Transmission Owner, and shall cause the Supplier's remotely started up block of generator units to be synchronized and at full output within fifteen (15) minutes.

15.6.4 Failure to Achieve Timely Synchronization

If a Supplier that has sold Quick Start Reserves fails to have the block of generator units synchronized in the amount of the Energy Bid pursuant to Section 15.6.2.6 of this Rate Schedule within fifteen (15) minutes of a remote start-up, the Supplier shall be subject to the provisions applicable to Suppliers of 10-Minute Non-Spinning Reserves and 30-Minute Reserves that fail to provide Energy within the time allotted; provided, however, that charges against Quick Start Reserves payments shall be based upon the blended rate of 85% of $P_{10MNSR,h}$ plus 15% of $P_{30MR,h}$, as applied in Section 15.6.5.1 of this Rate Schedule.

15.6.5 Payments to Suppliers; Payments by Load Serving Entities

15.6.5.1 A Supplier that provides Quick Start Reserves shall receive each Billing Period a payment for each block of generator units that provided Quick Start Reserves in any hour of the previous Billing Period, unless the block of generator units also produced Energy during the hour. The amount of this payment shall equal:

$$\sum_h \left(C_h * \left(0.85 * P_{10MNSR,h} + 0.15 * P_{30MR,h}\right) - Q_h * P_{30MR,h}\right)$$

where:

h = An hour in which the block of generator units provided Quick Start Reserves, unless the block of generator units produced Energy during the hour

C = Capacity in MWs of Hour-Ahead Bids for Energy for the block of generator units

P_{10MNSR} = Price of 10-Minute NSR (SENY) in the Day-Ahead Market

P_{30MR} = Price of 30-Minute Reserves (SENY) in the Day-Ahead Market

Q = Quantity of MWs from the block of generator units accepted into the 30-Minute Reserves market.

15.6.5.2 Any block of generator units requested for Quick Start Reserves for any portion of an hour shall be deemed to have provided Quick Start Reserves for the entire hour unless the block of generator units also produced Energy during the hour.

15.6.5.3**.** In addition to payments due to a Supplier of Quick Start Reserves pursuant to Section 15.6.5.1 of this Rate Schedule, the Supplier shall be eligible to receive payments for Energy, Installed Capacity, Operating Reserves, and other Ancillary Services pursuant to the other provisions of this Services Tariff.

15.6.5.4 Amounts due to a Supplier pursuant to this Rate Schedule that are attributable to local reliability shall be recovered from LSEs in the Transmission District of the Supplier selling the Quick Start Reserves on the basis of each LSE's contribution to Load share in the Billing Period in which the payment obligation is incurred. Amounts attributable to local reliability are those amounts incurred pursuant to Sections 15.6.2.1 and 15.6.3.1 of this Rate Schedule.

15.6.6 Dispute Resolution

15.6.6.1 In the event of a dispute between a Transmission Owner and a Supplier of Quick Start Reserves regarding the hours or MWs of Quick Start Reserves purchased by a Transmission Owner or the Energy output achieved within fifteen (15) minutes of a remote start-up, the Transmission Owner and Supplier shall attempt to resolve the dispute promptly, and either party may request the ISO to refer to the ISO logs to help resolve the dispute. If a Transmission Owner and a Supplier selling Quick Start Reserves cannot resolve any dispute regarding the hours or MWs of Quick Start Reserves purchased by a Transmission Owner or the Energy output achieved within fifteen (15) minutes of a remote start-up within fifteen (15) days, then the Transmission Owner and Supplier may resolve the dispute through the ISO's Expedited Dispute Resolution Procedures.

15.6.6.2 Disputes other than those addressed pursuant to Section 15.6.6.1 of this Rate Schedule may be resolved through the ISO's Dispute Resolution Process.

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15.7 Rate Schedule 7 - Charges for Intermittent Power Resource Forecasting Services

The ISO shall charge each Intermittent Power Resource, except for Intermittent Power Resources in a DER Aggregation, that depends on wind or solar energy as its fuel that is interconnected in the New York Control Area in order to provide Energy to the LBMP Market or bilaterally to a Load internal or external to the NYCA, pursuant to this ISO Services Tariff or the NYISO OATT, and that has entered commercial operation, for forecasting service pursuant to this Rate Schedule, provided however no charge shall be assessed against any Intermittent Power Resource in commercial operation as of January 1, 2002 with nameplate capacity of 12 MWs or fewer.

The ISO shall calculate and assess such charges each Billing Period.

15.7.1 Responsibilities

The ISO shall calculate a forecasting service charge which shall include a fixed component and a component that varies by the nameplate capacity of the Intermittent Power Resource subject to this charge ("Forecasting Service Charge"). Such charge shall be based upon the costs the NYISO incurs in producing a forecast of the expected generation output of each Intermittent Power Resource subject to this charge.

15.7.2 Charges

Each Billing Period, the ISO shall assess to each Intermittent Power Resource subject to this charge the portion of the following monthly Forecasting Service Charge allocated to that Billing Period:

- $500.00 as a fixed fee; and
- $6.20 / MW of name plate capacity.

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15.8 Rate Schedule 8 – Payments to RMR Generators

15.8.1 Payment to an RMR Generator Providing Service Pursuant to an RMR Agreement with an Availability and Performance Rate

The ISO shall make a payment each Billing Period to each RMR Generator providing service pursuant to an RMR Agreement with an Availability and Performance Rate that has been accepted for filing by the Commission, or the ISO may pay subject to refund pending Commission action. The payment shall equal:

$$\sum_{d \in P} \left(RMRAvoidCost_{g,d} + VarCost_{g,d} \right)$$

Where:

d = the relevant market day;

P = the relevant Billing Period;

g = the relevant RMR Generator that is providing service under an Availability and Performance Rate established pursuant to the ISO Tariffs and an RMR Agreement between the ISO and the RMR Generator;

$RMRAvoidCost_{g,d}$ = 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 38.8 and 38.17 of the OATT pending Commission action, shaped on a Capability Period basis, and Additional Costs in accordance with Section 38.16 of the OATT;

$$VarCost_{g,d} = Energy_{g,d} + AncServices_{g,d} + VSS_{g,d} + RS_{g,d}$$

Where:

$Energy_{g,d}$ = the energy cost of RMR Generator g for day d. The cost of all energy MWhs that are scheduled and produced in real-time by RMR Generator g that do not exceed RMR Generator g's Day-Ahead schedule shall be equal to the lesser of RMR Generator g's Day-Ahead reference levels and RMR Generator g's Day-Ahead Bids. The cost of all energy MWhs that are scheduled and produced in real-time (including Compensable Overgeneration, if any) that exceed RMR Generator g's Day-Ahead schedule (if any) shall be equal to the lesser of RMR Generator g's real-time reference levels and RMR Generator g's real-time Bids;

$AncServices_{g,d}$ = the cost of Operating Reserves and Regulation Service for RMR Generator g for day d. The cost of all MWhs of Operating Reserves that are scheduled and of Regulation Service that are scheduled and provided in real-time by RMR

Generator *g* that do not exceed RMR Generator *g*'s Day-Ahead schedule shall be equal to the lesser of RMR Generator *g*'s Day-Ahead reference levels and RMR Generator *g*'s Day-Ahead Bids. The cost of all MWhs of Operating Reserves and Regulation Service that are scheduled and provided in real-time by RMR Generator *g* that exceed RMR Generator *g*'s Day-Ahead schedule (if any) shall be equal to the lesser of RMR Generator *g*'s real-time reference levels and RMR Generator *g*'s real-time Bids;

$VSS_{g,d}$ = the Voltage Support Service payment for RMR Generator *g* for day *d* pursuant to Rate Schedule 2 of the ISO Services Tariff;

$RS_{g,d}$ = the Restoration Services payment for RMR Generator *g* for day *d* pursuant to Rate Schedule 5 of the ISO Services Tariff.

15.8.2 Performance Incentive Payment

The ISO will pay on a monthly basis an RMR Generator that is providing service pursuant to an RMR Agreement with an Availability and Performance Rate any Performance Incentive payment owed to that RMR Generator for its performance in that month in accordance with the following formulae.

PI_m = the amount of the Performance Incentive payment, calculated for each month *m*, and is a dollar value calculated as:

$$PI_m = \frac{1}{12} PI_{max} * \begin{cases} 50\%, & \text{for } LB_{PI} \leq PF_m < UB_{PI} \\ 80\%, & \text{for } UB_{PI} \leq PF_m < TL_{PI} \\ 100\%, & \text{for } TL_{PI} \leq PF_m \end{cases}$$

Where:

PI_{max} = the maximum annual Performance Incentive payment, calculated as 5% of the RMR Generator's *Non-CapEx Avoidable Costs;*

$Non\text{-}CapEx\ Avoidable\ Costs$ = the RMR Avoidable Costs the RMR Generator is authorized to recover annually, pursuant to an Availability and Performance Rate that has been accepted for filing by the Commission, or that the RMR Generator is recovering subject to refund pending Commission action, less the Capital Expenditures included in such RMR Avoidable Costs;

LB_{PI} = the Bandwidth Lower Bound, a percentage defined as:

$$LB_{PI} = \begin{cases} 0.9 * BL_{PI}, & if\ BL_{PI} < 50\% \\ BL_{PI} - 5\%, & if\ BL_{PI} \geq 50\% \end{cases}$$

UB_{PI} = the Bandwidth Upper Bound, a percentage defined as:

$$UB_{PI} = BL_{PI} + min\left\{\frac{1}{3}(100\% - BL_{PI}), \max\left\{5\%, \frac{1}{10}(100\% - BL_{PI})\right\}\right\}$$

TL_{PI} = the Target Limit, a percentage defined as:

$$TL_{PI} = BL_{PI} + min\left\{\frac{2}{3}(100\% - BL_{PI}), max\left\{10\%, \frac{1}{5}(100\% - BL_{PI})\right\}\right\}$$

Where:

BL_{PI} = the Baseline percentage determined for the RMR Generator's performance, as set forth in the RMR Generator's RMR Agreement.

PF_m = the RMR Performance Factor for month m, a percentage defined as:

$$PF_m = 100\% - \frac{\sum_{t=t_0}^{T}(max\{PLU_t - Pr_t, 0\})}{\sum_{t=t_0}^{T} PLU_t}$$

Where:

t_0 = the first RTD interval of month *m*;

T = the last RTD interval of month *m*;

Pr_t = the Real-Time output of the RMR Generator over RTD interval *t*, in MW; and

PLU_t = the Penalty Limit for Under-Generation of the RMR Generator over RTD interval *t*, expressed in MW, calculated in accordance with the ISO's Billing and Accounting Manual.

15.8.3 Availability Incentive Payment

The ISO will pay on a Capability Period basis an RMR Generator that is providing service pursuant to an RMR Agreement with an Availability and Performance Rate for any Availability Incentive payment owed to that RMR Generator. The ISO will make the Availability Incentive payment in the Billing Period following the first month of the Capability Period for a payment earned for the previous Capability Period in accordance with the following formulae.

AI_{cp} = the amount of the Availability Incentive, calculated for each Capability Period *cp*, and is a dollar value calculated as:

$$AI_{cp} = \frac{1}{2} AI_{max} * \begin{cases} 50\%, & \text{for } LB_{AI,cp} \leq EAF_{cp} < UB_{AI,cp} \\ 80\%, & \text{for } UB_{AI,cp} \leq EAF_{cp} < TL_{AI,cp} \\ 100\%, & \text{for } TL_{AI,cp} \leq EAF_{cp} \end{cases}$$

Where:

AI_{max} = the maximum Availability Incentive payment, calculated as 20% of the RMR Generators *Non-CapEx Avoidable Costs;*

$Non\text{-}CapEx\ Avoidable\ Costs$ = the RMR Avoidable Costs the RMR Generator is authorized to recover annually, pursuant to an Availability and Performance Rate that has been accepted for filing by the Commission, or that the RMR Generator is recovering subject to refund pending Commission action, less the Capital Expenditures included in such RMR Avoidable Costs;

$LB_{AI,cp}$ = the Bandwidth Lower Bound, a percentage defined as:

$$LB_{AI,cp} = \begin{cases} 0.9 * BL_{AI,cp}, & if\ BL_{AI,cp} < 50\% \\ BL_{AI,cp} - 5\%, & if\ BL_{AI,cp} \geq 50\% \end{cases}$$

$UB_{AI,cp}$ = the Bandwidth Upper Bound, a percentage defined as:

$$UB_{AI,cp} = BL_{AI,cp} + min\left\{\tfrac{1}{3}(100\% - BL_{AI,cp}), \max\left\{5\%, \tfrac{1}{10}(100\% - BL_{AI,cp})\right\}\right\}$$

$TL_{AI,cp}$ = the Target Limit, a percentage defined as:

$$TL_{AI,cp} = BL_{AI,cp} + min\left\{\tfrac{2}{3}(100\% - BL_{AI,cp}), max\left\{10\%, \tfrac{1}{5}(100\% - BL_{AI,cp})\right\}\right\}$$

Where:

$BL_{AI,cp}$ = the Baseline percentage for Capability Period *cp* determined for the RMR Generator's availability, as set forth in the RMR Generator's RMR Agreement;

EAF_{cp} = the RMR Generator's equivalent availability factor for Capability Period *cp*, a percentage defined as:

$$EAF_{cp} = 100\% * \left(\frac{\left(AH - (DH_{EU} + DH_{EP} + DH_{ESE})\right)}{PH}\right)$$

Where:

AH = the RMR generator's available hours, calculated for Capability Period *cp* in accordance with ISO procedures;

PH = the RMR Generator's period hours, calculated for Capability Period *cp* in accordance with ISO procedures, as the number of hours that the RMR Generator was in an active state;

DH_{EU} = the RMR Generator's unplanned derated hours, calculated for Capability Period *cp* in accordance with ISO procedures, as the product of unplanned derated hours and size of reduction, divided by net maximum capacity;

DH_{EP} = the RMR Generator's planned derated hours, calculated for Capability Period *cp* in accordance with ISO procedures, as the product of planned derated hours and size of reduction, divided by net maximum capacity; and

DH_{ESE} = the RMR Generator's net maximum capacity, determined in accordance with ISO procedures, less net dependable capacity, determined in accordance with ISO procedures, multiplied by available hours in accordance with ISO procedures, and divided by net maximum capacity.

GADS Data used to calculate Availability Incentive payments, as it may be modified by the ISO, shall be subject to review, challenge, and correction in accordance with Section 7.4 of the ISO Services Tariff.

15.8.4 Limitation on Total Penalties, Sanctions and Deficiency Charges Assessed to RMR Generators Providing Service Pursuant to an RMR Agreement with an Availability and Performance Rate

An RMR Generator that is providing service pursuant to an RMR Agreement with an Availability and Performance Rate is subject to all of the 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 pursuant to an RMR Agreement with an Availability and Performance Rate 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 the penalty or penalties are charged. The ISO shall charge any penalties to the RMR Generator and remit the revenues from each penalty, or any reduced amount, in accordance with the applicable provisions of the ISO Services Tariff.

15.8.5 Payment to an RMR Generator Providing Service Pursuant to an RMR Agreement with a Rate Other Than an Availability and Performance Rate

The ISO shall make a payment each Billing Period to each RMR Generator providing service pursuant to an RMR Agreement with a rate other than an Availability and Performance Rate that has been accepted for filing by the Commission, or the ISO may pay subject to refund pending Commission action. The payment shall equal:

$$\sum_{d \in P} \left(RMRCost_{g,d} + VarCost_{g,d} \right)$$

Where:

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

$RMRCost_{g,d}$ = the costs RMR Generator g is authorized to recover for day d pursuant to a rate for RMR Generator g that has been accepted for filing by the Commission, or that RMR Generator g is recovering subject to refund pending Commission action, shaped on a Capability Period basis, and Additional Costs in accordance with Section 38.16 of the OATT.

The definitions of the remaining variables in this equation are identical to the definitions for such variables set forth in Section 15.8.1 above.

15.8.6 Payment to a Generator that is Required to Continue Operating Beyond the Later of the 180th Day of the 365 Day Notice Period or its Requested Deactivation Date

Consistent with the rules set forth in Section 38.13 of the OATT and Sections 23.6 and 5.14.1.1 of the Services Tariff, commencing on the later of (a) the 181st day of the relevant 365 day notice period set forth in Attachment FF of the OATT (for purposes of this Rate Schedule 8, the “365 Day Notice Period”), or (b) the Generator’s requested deactivation date, the ISO shall make a payment each Billing Period to each Generator that remains in service as an Interim Service Provider. Generators that are in an ICAP Ineligible Forced Outage shall not be compensated as Interim Service Providers.

The payment to an Interim Service Provider shall equal:

$$\sum_{d \in P} \left(RMRAvoidCost_{g,d} + VarCost_{g,d} \right)$$

Where:

d = the relevant market day;

P = the relevant Billing Period;

g = the relevant Generator that satisfies the conditions set forth in Section 38.13 of the OATT, and Sections 23.6, 5.14.1.1 and 15.8.6 of the Services Tariff;

$RMRAvoidCost_{g,d}$ = the Avoidable Cost amount for Generator *g* for day *d* calculated by the ISO in accordance with Sections 38.8, 38.16 and 38.17 of the OATT, shaped on a Capability Period basis. The NYISO will incorporate Preexisting Capacity Bilaterals into its calculation of $RMRAvoidCost_{g,d}$ for Interim Service Providers consistent with the rules set forth below;

$$VarCost_{g,d} = Energy_{g,d} + AncServices_{g,d} + VSS_{g,d} + RS_{g,d}$$

Where:

$Energy_{g,d}$ = the energy cost of Generator *g* for day *d*. The cost of all energy MWhs that are scheduled and produced in real-time by Generator *g* that do not exceed Generator *g*'s Day-Ahead schedule shall be equal to the lesser of Generator *g*'s Day-Ahead reference levels and Generator *g*'s Day-Ahead Bids. The cost of all energy MWhs that are scheduled and produced in real-time (including Compensable Overgeneration, if any) that exceed Generator g's Day-Ahead schedule (if any) shall be equal to the lesser of Generator *g*'s real-time reference levels and Generator *g*'s real-time Bids;

$AncServices_{g,d}$ = the cost of Operating Reserves and Regulation Service for Generator *g* for day *d*. The cost of all MWhs of Operating Reserves that are scheduled and of Regulation Service that are scheduled and provided in real-time by Generator *g* that do not exceed Generator *g*'s Day-Ahead schedule shall be equal to the lesser of Generator *g*'s Day-Ahead reference levels and Generator *g*'s Day-Ahead Bids. The cost of all MWhs of Operating Reserves and Regulation Service that are scheduled and provided in real-time by Generator *g* that exceed Generator *g*'s Day-Ahead schedule (if any) shall be equal to the lesser of Generator *g*'s real-time reference levels and Generator *g*'s real-time Bids;

$VSS_{g,d}$ = the Voltage Support Service payment for Generator *g* for day *d* pursuant to Rate Schedule 2 of the ISO Services Tariff;

$RS_{g,d}$ = the Restoration Services payment for Generator *g* for day *d* pursuant to Rate Schedule 5 of the ISO Services Tariff.

If an Interim Service Provider has a Preexisting Capacity Bilateral, as such term is defined in Section 5.14.1.1 of the Services Tariff, then the ISO will reduce the *RMRAvoidCost* it calculates for the Interim Service Provider to reflect up to the revenues the ISO determines the Interim Service Provider is expected to receive under the Preexisting Capacity Bilateral.

If the Interim Service Provider's Preexisting Capacity Bilateral is with an Affiliate, or was entered into less than one year before the ISO received the Interim Service Providers Generator Deactivation Notice, then the *RMRAvoidCost* the ISO calculates for the Interim Service Provider shall be reduced by up to the revenues that the ISO determines the Interim Service Provider would reasonably be expected to receive if offered its Unforced Capacity at $0.00/kW-month into the ICAP Spot Market Auction conducted for the relevant Obligation Procurement Period based on the ISO's forecast of the Market-Clearing Price for the applicable ICAP Spot Market Auction.

Payments pursuant to this Section 15.8.6 shall cease at the conclusion of the 365 Day Notice Period.

15.8.7 Recovery of Capital Expenditures or Above Market Rates from Former RMR Generators and Former Interim Service Providers

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 necessary to permit a Generator to provide service during the term of an RMR Agreement or as an Interim Service Provider; or if the NYISO compensated an RMR Generator pursuant to this Rate Schedule 8 amounts that exceeded the

Generator's going-forward costs whilst providing RMR service; then in order for such a former RMR Generator or former Interim Service Provider to be permitted to return to participating in the ISO Administered Markets while it is eligible to receive market-based rates, the Generator will be required to repay to the ISO the higher of the repayment obligation determined in accordance with Section 15.8.7.1 below, or the repayment obligation determined in accordance with Section 15.8.7.2 below. The higher of the two repayment obligations, divided by the applicable number of repayment periods, is the "Monthly Repayment Obligation."

A Generator is "participating in the ISO Administered Markets while it is eligible to receive market-based rates" if the Generator (a) is not in a Mothball Outage or an ICAP Ineligible Forced Outage, and is not Retired, and (b) is not an RMR Generator or an Interim Service Provider.

The ISO shall apply the Monthly Repayment Obligation to the physical Generator that is a former RMR Generator or a former Interim Service Provider, without regard to any changes in ownership or control of that Generator. The Monthly Repayment Obligation shall be applied whenever the former RMR Generator or former Interim Service Provider is participating in the ISO Administered Markets while it is eligible to receive market-based rates, until the applicable repayment obligation has been fully repaid. The Monthly Repayment Obligation shall not be imposed while a former RMR Generator or former Interim Service Provider is in a Mothball Outage or IIFO, or is Retired. If a former RMR Generator or former Interim Service Provider returns from being Retired, or from being in a Mothball Outage or IIFO, to participate in the ISO Administered Markets while it is eligible to receive market-based rates, then the ISO shall recalculate and reinstate an updated Monthly Repayment Obligation.

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15.8.7.1 Recovery of Capital Expenditures from Former RMR Generators and Former Interim Service Providers

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, or if the ISO reimbursed all or a portion of the cost of a Capital Expenditure that was incurred to permit a Generator to provide service as an Interim Service Provider, and the Generator is no longer an Interim Service Provider or the subject of any RMR Agreement, then in order for the ISO to permit the Generator to be offered into or be scheduled in any ISO Administered Markets while it is eligible to receive market-based rates, the cost of Capital Expenditures (if any) that the ISO paid to enable the former RMR Generator to provide service under an RMR Agreement or to enable a former Interim Service Provider to provide service, less depreciation, plus interest, must be repaid to the ISO on a monthly basis over the period specified in the definition of "*mCapEx*" below. Depreciation will be calculated for each Capital Expenditure at the time the former RMR Generator or former Interim Service Provider proposes to re-enter the ISO Administered Markets.

A Generator that was an RMR Generator or an Interim Service Provider that deactivated and that wants to return to participating in any of the ISO Administered Markets while it is eligible to receive market-based rates must give the ISO at least 60 days advance notice of its desire to return to the ISO Administered Markets in order to permit the ISO to determine its Monthly Repayment Obligation (if any) and any associated credit requirement.

The following formula shall be used to determine the repayment obligation:

$$RMRCapExRecovery\ repayment\ obligation = \sum_{i \in I} \left(\sum_{j \epsilon M} A_{ij} - \sum_{k \in Y} P_{ik} \right)$$

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Where:

i = a Capital Expenditure in I, the set of all Capital Expenditures for the former RMR Generator or former Interim Service Provider;

j = a month in M, the set of all months that the former RMR Generator or former Interim Service Provider received payment for Capital Expenditure i;

k = a year in Y, the set of all years beginning with the year Capital Expenditure i entered service or was otherwise integrated into the RMR Generator or Interim Service Provider, or the year the NYISO terminated the RMR Agreement if Capital Expenditure i was not completed or did not enter service while the Generator was operating under an RMR Agreement, and continuing to the present year;

A_{ij} = the payment made to the former RMR Generator or former Interim Service Provider in month j, for Capital Expenditure i;

P_{ik} = the annual depreciation expense, determined by the ISO, for Capital Expenditure i in year k; and

For the component of a former RMR Generator's or former Interim Service Provider's Above Market Revenues that is Capital Expenditures, the value derived in the calculation above shall be divided by "*mCapEx*" months;

mCapEx = For a former RMR Generator, the shorter of 36 months or twice the duration of the applicable RMR Agreement in months. For a former Interim Service Provider, twelve months. Alternatively, if the former RMR Generator or former Interim Service Provider elects to repay its entire obligation before it begins participating in the ISO Administered Markets at market-based rates, then *mCapEx* shall be one month.

Accumulated interest will be computed on a quarterly basis and assessed based on the dates the ISO paid the former RMR Generator or former Interim Service Provider for each Capital Expenditure. Following the date a former RMR Generator or former Interim Service Provider returns to participating in the ISO Administered Markets while it is eligible to receive market-based rates, a fixed interest rate will be used to determine the Monthly Repayment Obligation.

The repayment obligation specified in this Section 15.8.7.1 shall remain in effect until all Capital Expenditures that are due (as determined in accordance with the formula set forth above) have been repaid. As explained in Section 15.8.7 of this Rate Schedule 8, the repayment obligation shall take effect, be reinstated, or remain in effect (as appropriate) (i) if a former RMR

Generator does not deactivate at the conclusion of its RMR Agreement, or (ii) if a former Interim Service Provider does not deactivate at the conclusion of the 365 Day Notice Period, or (iii) if a former RMR Generator that entered a Mothball Outage, an ICAP Ineligible Forced Outage or Inactive Reserves returns to service from such state, or (iv) if a former Interim Service Provider that entered a Mothball Outage or an ICAP Ineligible Forced Outage returns to service from such state, or (v) if a former RMR Generator or former Interim Service Provider becomes Retired and subsequently returns to service as a new Generator, and/or (vi) if a former RMR Generator or former Interim Service Provider is sold, leased or otherwise transferred to a new owner or owners and remains in service or returns to service.

15.8.7.2 Recovery of Above Market Revenues from Former RMR Generators

If the ISO made payments to a Generator under Section 15.8.5 of this Rate Schedule 8 to permit the Generator to provide service during the applicable term of an RMR Agreement, and the former RMR Generator is no longer the subject of any RMR Agreement, and the former RMR Generator continues participating in, or returns to, the ISO Administered Markets while it is eligible to receive market-based rates; then the cost of the Above Market Revenues (including but not limited to the ISO's reimbursement of the cost of Capital Expenditures), that the ISO paid to compensate the Generator for providing RMR service, less depreciation where applicable, plus interest, must be repaid to the ISO on a monthly basis. The period over which Above Market Revenues must be repaid is specified in the definition of "*mAMR*" below.

The following formula shall be used to determine the Above Market Revenue repayment obligation:

$$Above\ RMRAvoidCost\ Revenue_g = max\{0,\ \sum_{d \in ToS}(RMRCost_{g,d} - \ RMRAvoidCost_{g,d})\}$$

Where:

Above RMRAvoidCost Revenue $_g$ = the difference between (x) the total revenues Generator g would have been eligible to receive in reimbursement of its RMR Avoidable Costs during the term of the RMR Agreement if it had been compensated at a rate developed in accordance with Section 15.8.1 of this Rate Schedule 8 (excluding any payments that Generator *g* would have been eligible to receive as Performance Incentives or Availability Incentives), and (y) the total revenues Generator g received in accordance with its accepted RMR Agreement to reimburse RMR Costs during the term of that RMR Agreement, paid in accordance with Section 15.8.5 of this Rate Schedule 8;

ToS = the duration of the applicable RMR Agreement;

$RMRAvoidCost_{g,d}$ = The revenue Generator *g* would have received for day *d* if it had been compensated for its RMR Avoidable Costs at a rate developed by the ISO in accordance with Section 15.8.1 of this Rate Schedule 8 (without Performance Incentives or Availability Incentives), using the market participation, commitment, scheduling and dispatch that occurred on day *d*; and

$RMRCost_{g,d}$ = the payment RMR Generator *g* received for day *d* in accordance with Section 15.8.5 of this Rate Schedule 8, excluding payment for Variable Costs.

The *Above RMRAvoidCost Revenue* shall be divided by "*mAMR*" to determine the Monthly Repayment Obligation.

mAMR = the shorter of 36 months or twice the duration of the applicable RMR Agreement in months. Alternatively, if the former RMR Generator elects to repay its entire obligation before it begins participating in the ISO Administered Markets at market-based rates, then *mAMR* shall be one month.

Accumulated interest will be computed and assessed quarterly, on a *pro rata* basis, based on the date of payment to the Generator for each relevant Billing Period *P* (as defined in Section 15.8.1 of this Rate Schedule 8). Following the date a former RMR Generator returns to participating in the ISO Administered Markets while it is eligible to receive market-based rates, a fixed interest rate will be used to determine the Monthly Repayment Obligation.

The definitions of the remaining variables in this equation are identical to the definitions for such variables set forth in Sections 15.8.1 and 15.8.7.1 above.

The reimbursement obligation specified in this Section 15.8.7.2 shall remain in effect until the entire amount, including interest has been reimbursed. As explained in Section 15.8.7 of this Rate Schedule 8, the reimbursement obligation shall take effect, be reinstated, or remain in effect (as appropriate) whenever a former RMR Generator continues participating in, or returns to, the ISO Administered Markets while it is eligible to receive market-based rates. The reimbursement obligation shall continue to apply or shall be reinstated, as appropriate, when (i) a former RMR Generator that entered a Mothball Outage, an ICAP Ineligible Forced Outage or Inactive Reserves returns to service from such state, or (ii) a former RMR Generator becomes Retired and subsequently returns to service as a new Generator, and/or (iii) a former RMR Generator is sold, leased or otherwise transferred to a new owner or owners and remains in service or returns to service.