

## **Rate Schedule 1**

### **Market Administration and Control Area Services Charge**

#### **1. Parties to Which Charges Apply**

A. The ISO shall charge and each Customer taking service under the ISO Services Tariff, the ISO OATT, or both, shall pay the applicable “ISO Services Charge” on all services provided under the Tariff. Market Participants taking service under both the ISO Services Tariff and the ISO OATT shall pay the applicable ISO Services Charges as calculated under Sections 3.A through C of this Rate Schedule and under Sections 2.B.3 and 2.B.4 of Rate Schedule 1 of the ISO OATT. Market Participants taking service under the ISO OATT only shall pay the applicable ISO Services Charges as calculated under Rate Schedule 1 of the ISO OATT.

B. Each Market Participant that sells or purchases Energy, including Demand Side Resources, Special Case Resources and Emergency Demand Response Program participants, sells or purchases Capacity, or provides Ancillary Services in the ISO Administered Markets utilizes Market Services and must enter into a Service Agreement under the Tariff, as set forth in Attachment A; and each entity that withdraws Energy to supply Load within the NYCA or provides Installed Capacity to an LSE serving Load within the NYCA utilizes the Control Area Services provided by the ISO and benefits from the reliability achieved as a result of ISO Control Area Services, and must enter into a Service Agreement under this Tariff, as set forth in Attachment A; each entity that has its virtual bids

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accepted and thereby engages in Virtual Transactions and each entity that purchases Transmission Congestion Contracts, excluding Transmission Congestion Contracts that are created prior to [the date that the Commission issues an order approving these revisions], utilizes Market Services and must enter into a Services Agreement under this Tariff, as set forth in Attachment A.

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## **2. Billing**

For the ISO Services Charges calculated under Section 3.A of this Rate Schedule, the ISO shall charge each Customer based on the product of: (i) the applicable ISO Services Charges rates; and (ii) the Customer's applicable injection billing units and/or withdrawal billing units for the month. The Customer's injection billing units shall be based on its Actual Energy Injections (for all internal injections) or Scheduled Energy Injections (for all Import Energy injections) in the New York Control Area, including injections for wheelthroughs. The Customer's withdrawal billing units shall be based on the Actual Energy Withdrawals for all Transactions to supply Load in the NYCA and hourly Energy schedules for all Wheels Through and Exports.

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For the ISO Services Charges calculated under Section 3.B and 3.C of this Rate Schedule, the ISO shall charge each Customer based on the product of: (i) the applicable ISO Services Charges rate; and (ii) the Customer's Actual Energy Withdrawals for all Transactions to supply Energy to the LBMP market in the NYCA and all other purchases from the LBMP markets to supply Load outside the NYCA.

For Customers participating in the ISO's Special Case Resources program or its Emergency Demand Response Program the ISO Services Charges calculated under Section 3.A of this Rate Schedule shall be the product of: (i) the applicable ISO Services Charge rates and (ii) the Customer's applicable billing units for the month. The Customer's billing units shall be based on the total compensable injection MWh.

For Customers purchasing Transmission Congestion Contracts or engaged in Virtual Transactions, the ISO Services Charges calculated under Section 3.A of this Rate Schedule shall be the product of : (i) the applicable ISO Services Charges rate; and (ii) the Customer's applicable billing units for the month.

For Customers purchasing Transmission Congestion Contracts, the Customer's billing units shall be based on the settled Transmission Congestion Contract MWh. For Customers engaging in Virtual Transactions, the Customer's billing units shall be based on total cleared virtual bid MWh.

### **3. Computation of Rate**

The ISO Services Charge shall consist of three components and shall be recovered on a monthly basis in accordance with the following processes:

#### **A. ISO Annual Budget and FERC Regulatory Fees Component**

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1. The responsibility for the sum of (i) the ISO's annual budget including the costs listed in Section 4A of this Rate Schedule; and (ii) the ISO's FERC Regulatory fees, shall be allocated 20% to all injection billing units as described in Section 2 of this Rate Schedule and 80% to all withdrawal billing units as described in Section 2 of this Rate Schedule. The current 80%/20% cost allocation shall remain unchanged through at least December 31, 2011 and shall continue to remain unchanged until such point in time that a study is conducted and the results of the study warrant changing the 80%/20% cost allocation. The following provisions prescribe the process and timeline for the review and, if warranted by the results of a future study, modification of the 80%/20% cost allocation on a going forward basis:

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(i) A vote of the Management Committee will be taken in the third calendar quarter of 2010 on whether a new study should be conducted during late-2010 and 2011 to allow modification of the 80%/20% cost allocation, if warranted by the results of the study, to be implemented by January 1, 2012. A positive vote by 58% of the Management Committee will be required to go forward with the study, but there will no longer be a “material change” standard as was historically applied to the determination of whether a study should be conducted.

(ii) If the Management Committee vote discussed in (i) above determines that a study should not be conducted, the 80%/20% cost allocation between withdrawal billing units and injection billing units shall be extended through at least December 31, 2012. In the third calendar quarter of 2011, a vote will be taken on whether a new study should be conducted during late-2011 and 2012 to allow modification of the percentage allocation, if warranted by the results of the study, to be implemented by January 1, 2013. Unless a 58% vote of the Management Committee is registered in favor of declining to go forward with the study, the study will be conducted.

(iii) If the Management Committee vote in the third calendar quarter of 2011 discussed in (ii) above determines that a study should not be conducted, the current 80%/20% cost allocation shall remain unchanged until such point in time

as the Management Committee determines that a study shall be conducted and the results of that study warrant changing the percentage allocation between withdrawal billing units and injection billing units. If the Management Committee vote in the third calendar quarter of 2011 discussed in (ii) above determines that a study should not be conducted, the Management Committee will revisit the issue of conducting a study annually in the third calendar quarter of each year using the same voting standard (*i.e.* the study gets performed unless 58% of the Management Committee votes not to commission the study) that was applied to the Management Committee vote in the third calendar quarter of 2011 discussed in (ii) above.

(iv) If, and when, the Management Committee determines a study shall be conducted:

- (a) Such study shall be completed, and the results thereof shared with Market Participants, before the end of the second calendar quarter of the year prior to the date on which a possible change to the then current allocation may become effective; and
- (b) The ISO will present a draft study scope to Market Participants for consideration and comment before the ISO issues the study scope as part of its Request For Proposal process to retain a consultant to

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perform the study. A meeting shall be held with Market Participants to discuss the components (*e.g.*, categories of costs considered, allocation of benefits, unbundling, etc.) that should be included in the draft study scope before the draft is issued by the ISO.

2. The rate for injection billing units shall be the quotient of 20% of the sum of the ISO's annual budget and FERC regulatory fees divided by the total annual estimated injection billing units, as described in Section 2 of this

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Rate Schedule. The rate for withdrawal billing units shall be the quotient of 80% of the sum of the ISO's annual budget and FERC regulatory fees divided by the total annual estimated withdrawal billing units as described in Section 2 of this Rate Schedule.

3. The rates derived in pursuant to Sections 3.A.1 and 2 above shall then be multiplied by each customer's injection billing units and withdrawal billing units, as appropriate, for the month, as described in Section 2 of this Rate Schedule.
4. For Customers that purchase Transmission Congestion Contracts or engage in Virtual Transactions their portion of the sum of (i) the ISO's annual budget including the costs listed in Section 4.A of this Rate Schedule; and (ii) the ISO's FERC Regulatory fees, shall be calculated and billed as follows:

(i) For Calendar Year 2010:

(a) \$0.020 per MWh for Transmission Congestion Contracts for calendar year 2010, based on a \$6.7 million projected 2010 annual revenue requirement.

(b) \$0.065 per cleared MWh for Virtual Transactions for calendar year 2010 based on a \$2.0 million projected 2010 annual revenue requirement.

(ii) For Subsequent Calendar Years

Each Customer shall be charged a rate computed annually based on the product of the annual revenue requirement adjusted for the over or under collection of the prior year's annual revenue requirement, divided by the three year rolling average of the billing units, where:

- (a) the annual revenue requirement is determined using an escalation factor calculated as the percentage change in the originally-approved ISO budget between the calendar year two years prior to the current calendar year (“Calendar Year Minus 2”) and the calendar year one year prior the current calendar year (“Calendar Year Minus 1”);
- (b) the over/under collection of the prior year’s annual revenue requirement is calculated for the period between July of Calendar Year Minus 2 and June of Calendar Year Minus 1. For the purpose of this calculation the annual revenue requirement will be converted to a monthly requirement and then aggregated across the 12 months;
- (c) the three year rolling average of billing units is calculated using an annual average of the billing units for the period between July of the calendar year four years prior to the current calendar year (“Calendar Year Minus 4”) and June of Calendar Year Minus 1.

However, the annual rate computed will be subject to a 25% maximum increase or decrease for each year. Revenue collected pursuant to this Section 3.A.4 will be disbursed monthly to all withdrawal billing units as described in Section 2 of this Rate Schedule and to all injection billing units as described in Section 2 of this Rate Schedule on the same basis described in Section 3.A.1 of this Rate Schedule.

5. For Customers participating in the ISO's Special Case Resource program or its Emergency Demand Response Program their portion of the sum of (i) the ISO's annual budget including the costs listed in Section 4.A of this Rate Schedule; and (ii) the ISO's FERC Regulatory fees, shall be billed at the same rate charged to injection billing units as described in Section 2 of this Rate Schedule. The rate will be reset annually to match the current calendar year's rate for injections. Revenue collected pursuant to this Section 3.A.5 will be disbursed monthly to all withdrawal billing units as described in Section 2 of this Rate Schedule and to all injection billing units as described in Section 2 of this Rate Schedule on the same basis described in Section 3.A.1 of this Rate Schedule.

**B. Unbudgeted Costs Component**

Except with respect to bad debt loss and working capital contribution costs, the responsibility for those costs listed in Section 4.A of this Rate Schedule that are neither (i) included in the ISO's annual budget nor (ii) FERC assessed regulatory fees, shall be allocated 100% to all withdrawal billing units. The rate to be applied to withdrawal billing units in each month shall be the quotient of the amount of these costs to be included in the month, as determined by the ISO, divided by the total estimated withdrawal billing units for the month, as described in Section 2 of this Rate Schedule. This rate shall then be multiplied by each Customer's withdrawal billing units for the month. The responsibility for costs associated with bad debt losses and working capital contributions shall be allocated pursuant to Attachments U and V of the ISO OATT.

C. ISO Start-Up and Formation Costs Component

The costs listed in Section 4.B of this Rate Schedule shall be estimated each month for the following month, shall be divided by the total estimated withdrawal billing units as described in Section 2 of this Rate Schedule, for the following month and shall be posted on the ISO's website prior to the start of the subject month. This rate is then multiplied by each customer's withdrawal billing units for the subject month.

**4. ISO Costs**

A. ISO costs to be recovered through this ISO Services Charge shall include the costs listed in Section 3A of Rate Schedule 1 of the ISO OATT and the costs incurred by the ISO that are "directly assignable" to the services provided by the ISO under this Tariff that are not recoverable under Rate Schedule 1 of the ISO OATT. Costs recoverable under this charge shall include costs related to: the ISO's administration of the LBMP Markets; the ISO's administration of Installed Capacity requirements and an Installed Capacity Market; the ISO's administration of Control Area Services, other than Ancillary Services provided under the ISO OATT; the ISO's administration of the ISO Market Power Monitoring Program; other activities related to the maintenance of reliability in the NYCA; and costs related to any indemnification of or by the ISO pursuant to Section 12.4 of this Tariff, together the annual ISO budget; and

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- B. Fifty (50) percent of the costs associated with the start-up and formation of the ISO, plus interest, equaling \$27.45 million, plus interest, less one-half of the start-up costs already collected by the ISO under the ISO OATT. These costs will be amortized over a period from September 1, 2000 through December 31, 2004.

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

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## **Rate Schedule 2**

### **Payments for Supplying Voltage Support Service**

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

The rate provided in this Rate Schedule shall be used to calculate payments to all eligible Suppliers providing Voltage Support Service as applied on a Resource-specific basis (or Qualified Non-Generator Voltage Support Resource-specific). The ISO shall calculate payments on an annual basis, and make payments monthly.

#### **1.0 Responsibilities**

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

#### **1.1 Suppliers**

To qualify for payments, Suppliers of Voltage Support Service shall provide a Resource that has an AVR, or a Qualified Non-Generator Voltage Support Resource. 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 Suppliers to operate their Resources and Qualified Non-Generator Voltage Support Resources within these demonstrated reactive capability limits. Suppliers of Voltage Support Service will test their Resources and Qualified Non-Generator 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 Resource's or Qualified Non-Generator 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 Resource's stated reactive capability. The requirement for a Resource or Qualified Non-Generator Voltage Support Resource ("Resource") to absorb Reactive Power may be set aside by the ISO with input from the Transmission Owner in whose Transmission District the 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 Resource be able to absorb Reactive Power, the ISO shall have determined that: 1) the resource is unable, due to transmission system configuration, to absorb Reactive Power; 2) the ability of the Resource to produce Reactive Power is needed for system reliability; and 3) for purposes of system reliability the Resource does not need to have the ability to absorb Reactive Power.

## **2.0 Payments**

Each month, Suppliers whose Resource(s) meet the requirements to supply Installed Capacity, as described in Article 5 of the ISO Services Tariff, and are under contract to supply Installed Capacity shall receive one-twelfth (1/12<sup>th</sup>) of the annual payment calculated under Section 2.0a of this Rate Schedule, for Voltage Support Service. To the extent Suppliers of Installed Capacity are electrically located outside the NYCA, payments for Voltage Support Service will be subject to criteria established by the ISO.

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 (1/12<sup>th</sup>) of the annual payment calculated under Section 2.0a 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 (1/12<sup>th</sup>) the annual payment calculated under Section 2.0a of this Rate Schedule, pro-rated by the number of hours that it is energized in that month, as recorded by the ISO.

### **(a) Annual Payment for Voltage Support Service**

For purposes of the calculation set forth in Section 2.0 of this Rate Schedule, the annual payment to Suppliers qualified and eligible to provide Voltage Support Service shall equal: (i) in the case of Generators and synchronous

condensers the product of \$3919/MVAr and the tested MVAr capacity of the Generator or synchronous condenser; (ii) in the case of Qualified Non-Generator Voltage Support Suppliers, other than the Cross-Sound Scheduled Line, the product of \$3919/MVAr and its tested MVAr capacity as determined pursuant to the ISO Procedures; and (iii) in the case of the Cross-Sound Scheduled Line, the product of \$3919/MVAr and the tested, Reactive Power (MVAr) capacity measured at maximum real power flow.

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**(b) Lost Opportunity Costs**

A Supplier of Voltage Support Service from a Generator that is being dispatched by the ISO shall also receive a payment for Lost Opportunity Costs (“LOC”) when the ISO directs the resource to reduce its real power (MW) output below its Economic Operating Point in order to allow the resource 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 product of: (a) the MW of output reduction; (b) the time duration of reduction in hours or fractions thereof; and (c) the Real-Time LBMP at the Generator bus minus the Generator’s Energy Bid for the reduced output of the Generator. The details of the Lost Opportunity Cost payments are as follows:

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

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

Where:

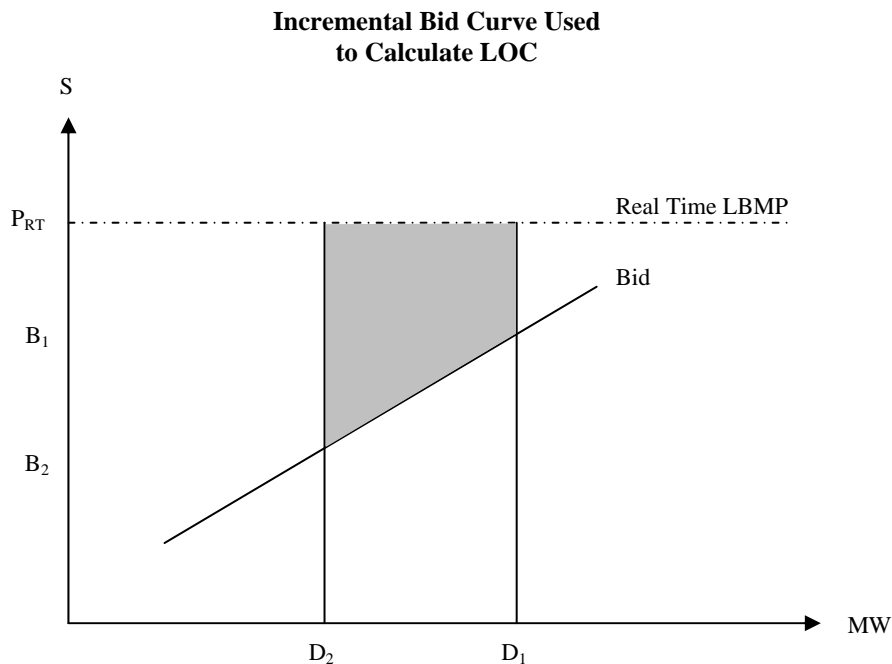
$P_{\text{RT}}$  = Real-Time LBMP

$D_1$  = Original dispatch point, which shall be equal to the Generator’s Economic Operating Point.

$D_2$  = New dispatch point, which shall be the greater of the Generator’s Real-Time Scheduled Energy Injection, the Generator’s Actual Energy Injection, or the amount of Energy the Generator is scheduled to produce for the hour in the Day-Ahead Market.

Bid = Bid curve or Generation supplying Voltage Support Service

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



**(c) 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.

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**(e) Failure to Perform by Suppliers**

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

- (1) fails at the end of 10 minutes to be within 5% (+/-) of the requested Reactive Power (MVAR) level of production or absorption as requested by the ISO or applicable Transmission Owner for levels below its Normal Operating limit which must be at least 90% of its Dependable Maximum Net Capability (DMNC).
- (2) fails at the end of 10 minutes to be at 95% or greater of the Resource's demonstrated Reactive Power capability (tested at its Normal Operating Limit or at 90% of its DMNC, whichever is greater in MW) in the

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appropriate lead or lag direction when requested to go to maximum  
lead or lag reactive capability by the ISO or applicable  
Transmission Owner.

Whether the Resource or Qualified Non-Generator Voltage Support Resource has failed to provide Voltage Support Service in a Contingency shall be defined by ISO Procedures. Suppliers of Voltage Support Service that fail to comply with the ISO Procedures will be assessed charges by the ISO in the manner described in subsections “f” and “g” below.

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

Initial Failure: If a Resource or a Qualified Non-Generator 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 one-twelfth (1/12th) of the annual payment for that specific Resource or a Qualified Non-Generator 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). The Supplier shall also be liable for any additional cost in procuring replacement Voltage Support Service including LOC incurred by the ISO as a direct result of the Supplier's non-performance.

Repeated Failures: For each instance of failure to perform, the non-complying Supplier will be subject to the charges described herein. If a Resource fails to comply

with the ISO's request on three (3) separate days, within a thirty (30) day period, then upon the third occurrence, the non-complying Supplier will no longer be eligible for Voltage Support Service payments for service provided by that Resource or Qualified Non-Generator Voltage Support Resource. The ISO may reinstate payments once the Supplier complies with the following conditions to the ISO's satisfaction:

- (1) the Supplier's Resource or Qualified Non-Generator Voltage Support Resource must successfully perform a Reactive Power (MVAR) capability test, and
- (2) the Resource or Qualified Non-Generator 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 during this period.

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

If a Supplier's Resource or Qualified Non-Generator 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 Resource or Qualified Non-Generator 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 Resource or Qualified Non-Generator 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 Resource or Qualified Non-Generator Voltage Support Resource until the Supplier complies with the following conditions to the ISO's satisfaction:

- (1) the Supplier's Resource or Qualified Non-Generator Voltage Support Resource shall successfully perform a Reactive Power (MVar) capability test, and
- (2) the Resource 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 during this period.

### **3.0 Consistency 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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### **Rate Schedule 3**

#### **Payments for Regulation Service**

This Rate Schedule applies to Suppliers that provide Regulation Service to the ISO.

Transmission Customers will purchase Regulation Service from the ISO under the ISO OATT.

#### **1.0 Obligations of the ISO and Suppliers**

##### **1.1 The ISO shall:**

- (a) Establish Regulation Service criteria and requirements in the ISO Procedures to ensure that 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, as described in Section 2.0 of this Rate Schedule;

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- (f) Pay Suppliers for providing Regulation Service as described in Sections 4.0, 5.0, 6.0 and 7.0 of this Rate Schedule; and
- (g) Monitor Suppliers' performance to ensure that they provide Regulation Service as required, as described in Section 3.0 of this Rate Schedule.

**1.2 Each Supplier shall:**

- (a) Register with the ISO the capacity its resources are qualified to bid in the Regulation Services market;
- (b) 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;
- (c) Not use, contract to provide, or otherwise commit Capability that is selected by the ISO to provide Regulation Service to provide Energy or Operating Reserves to any party other than the ISO;
- (d) Pay any charges imposed under this Rate Schedule including, if they are re-instituted the charges described in Section 8.0 of this Rate Schedule;
- (e) 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.

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

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

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

- (b) Real-Time Market: The ISO shall establish a Real-Time Market for Regulation Service and will establish a real-time Regulation Service market clearing price in each interval. During any period when the ISO suspends Resources' obligation to follow the AGC Base Point Signals sent to Regulation Service providers, pursuant to Section 9.0 of this Rate Schedule, the Real-Time Market clearing price for Regulation Service shall automatically be set at zero, which shall be the price used for real-time balancing and settlement purposes. The ISO shall select Suppliers for Regulation Service from those that have Bid to provide Regulation Service from Resources that meet the qualification standards and criteria established in the ISO Procedures.
- (c) The ISO shall establish separate market clearing prices for Regulation Service in the Day-Ahead Market and the Real-Time Market under Sections 4.0, 5.0 and 7.0 of this Rate Schedule. The ISO shall also compute Regulation Revenue

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

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

(b) Bids rejected by the ISO may be modified and

resubmitted by the Supplier to the ISO in accordance with the terms of the ISO  
Tariff.

- (c) Each Bid shall contain the following information: (i) the maximum amount of Capability (in MW) that the Resource is willing to provide for Regulation Service; (ii) the Resource's regulation response rate (in MW/Minute) which must be sufficient to permit that Resource to provide the offered amount of Regulation Service within an RTD interval provided, however, that the regulation response rate for Demand Side Resources shall be at least equal to its energy response rate; (iii) the Supplier's Availability Bid Price (in \$/MW); 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 Service offer (in MWs) from a Limited Energy Storage Resource to account for the Energy storage capacity of such Resource.

### **3.0 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.

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- (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 Performance Tracking System shall compute the difference between the Energy

actually supplied and the Energy scheduled by the ISO for all Suppliers serving Load within the NYCA as set forth in the ISO Procedures. The ISO shall use these values to reduce Regulation Service payments pursuant to Section 5.4 of this Rate Schedule.

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

#### **4.0 Regulation Service Settlements - Day-Ahead Market**

##### **4.1 Calculation of Day-Ahead Market Clearing Prices**

The ISO shall calculate a Day-Ahead Market clearing price for Regulation Service each hour of the following day. The Day-Ahead Market clearing price for each hour shall equal the Day-Ahead Shadow Price of the ISO's Regulation Service constraint for that hour, which shall be established under the ISO Procedures. Day-Ahead Shadow Prices will be calculated by the ISO's SCUC. Each hourly Day-Ahead Shadow Price shall equal the marginal Bid cost of scheduling Resources to provide additional Regulation Service in that hour, including any

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

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## **4.2 Other Day-Ahead Payments**

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

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.

## **5.0 Regulation Service Settlements - Real-Time Market**

### **5.1 Calculation of Real-Time Market Clearing Prices**

The ISO shall calculate a Real-Time Market clearing price for Regulation Service for every RTD interval, except as noted in Section 9.0 of this Rate Schedule. Except when the circumstances described below in Section 5.1A apply, the Real-Time Market clearing 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. 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 calculated during the third RTD pass described in Section I.A.1.b.iii of Attachment B to this ISO Services Tariff, and Section I.A.1.b.iii of Attachment J to the ISO OATT. As a result, the Shadow Price shall include the Real-Time Regulation Service Bid of the marginal Resource selected to provide Regulation Service (or the applicable price on the Regulation Service Demand Curve during shortage conditions), plus any margins on the sale of Energy or Operating Reserves in the Real-Time Market that Resource would forego if scheduling it to provide additional Regulation Service would lead to it being scheduled to provide less Energy or Operating Reserves. Shadow Prices shall also be consistent with the Regulation Service Demand Curves described in Section 7.0 of this Rate Schedule, which will ensure that Regulation Service is not scheduled by RTC at a cost greater than the Demand Curve indicates should be paid.

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

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

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

**5.2 Real-Time Regulation Service Balancing Payments**

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

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

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

- (b) When the Supplier's real-time Regulation Service schedule is greater than its Day-Ahead Regulation Service 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 Regulation Service; and (ii) the difference between the Supplier's real-time Regulation Service schedule and its Day-Ahead Regulation Service schedule (subject to possible adjustments pursuant to Section 5.4 of this Rate Schedule.)

### **5.3 Other Real-Time Regulation Service Payments**

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

No payments shall be made to any 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.

Finally, whenever a Supplier's real-time Regulation Service schedule is reduced by the ISO to a level lower than its Day-Ahead schedule for that product, the Supplier's Day-Ahead Margin shall be protected after accounting for any margin associated with other products that the Supplier's is scheduled to provide in real-time, provided however, that the Day-Ahead Margin of a Limited Energy Storage Resource may not be protected if the ISO has reduced its real-time Regulation Service offer to a level lower than its Day-Ahead schedule to account for the Energy storage capacity of such Limited Energy Storage Resource. The rules governing the calculation of these Day-Ahead Margin Assurance Payments are set forth in Attachment J to this ISO Services Tariff.

#### **5.4 Performance-Based Adjustments to Regulation Service Payments**

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

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

Where:

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

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

DARcap<sub>i</sub> is the Regulation Service Capability (in MW) offered by the Resource and selected by the ISO in the Day-Ahead Market in the hour that includes RTD interval *i*;

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

RTRcap<sub>i</sub> is the Regulation Service Capability (in MW) offered by the Resource and selected by the ISO in the Real-Time Market in RTD interval *i*;

*s<sub>i</sub>* is the number of seconds in interval *i*; and

K<sub>PI</sub> is a factor, 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 determined pursuant to the following equation:

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

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Where:

PI is the performance index of the Resource; and

PSF is the payment scaling factor, established pursuant to ISO Procedures. The PSF shall be set between 0 and the minimum performance index required for payment of Availability payments. The PSF is established to reflect the extent of ISO compliance with the standards

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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. The factor  $K_{PI}$  shall initially be set at 1.0 for Limited Energy Storage Resources.

## **6.0 Energy Settlement Rules for Generators Providing Regulation Service**

### **6.1 Energy Settlements**

A. For any interval in which a Generator is providing Regulation

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

- B. For any hour in which a Limited Energy Storage Resource 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:

$$\text{Energy Settlement}_h = \text{Net MWHR}_h * \text{LBMP}_h$$

Where:

$\text{Net MWHR}_h$  = 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

$\text{LBMP}_h$  = the time-weighted average LBMP in hour h calculated for the location of that Limited Energy Storage Resource

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

For any interval in which a Generator that is providing Regulation Service receives an AGC Base Point Signal that is higher than its RTD Base Point Signal, it shall receive or pay a Regulation Revenue Adjustment Payment (“RRAP”) or Regulation Revenue Adjustment Charge (“RRAC”) calculated under the terms of this subsection, provided however no RRAP shall be payable and no RRAC shall be charged to a Limited Energy Storage Resource. If the Energy Bid Price of such a Generator is higher than the LBMP at its location in that interval, the Generator shall receive a RRAP. Conversely, for any interval in which such a Generator’s Energy Bid Price is lower than the LBMP at its location at that interval, the Generator shall be assessed a RRAC. RRAPs and RRACs shall be calculated using the following formula:

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

Where:

s is the number of seconds in the RTD interval;

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

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

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

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

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

Where:

s is the number of seconds in the RTD interval;

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

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## **7.0 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 Service markets. The market clearing prices for Regulation Service calculated pursuant to Sections 4.1 and 5.1 of this Rate Schedule shall take account of the demand curve established in this Section so that Regulation Service is not purchased by SCUC or RTC 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 Service that the ISO would seek to maintain in that hour. The ISO will then define a Regulation Service demand curve for that hour as follows:

For quantities of Regulation Service that are less than or equal to the target level of Regulation Service minus 25 MW, the price on the Regulation Service demand curve shall be \$300/MW.

For quantities of Regulation Service 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 \$250/MW.

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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 Service 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 ~~Advisor~~Monitoring Unit when it conducts this investigation.

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Superseding ~~Original~~ First Revised Sheet No. 279.01

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 Advisor~~ 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

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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

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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 7.0 is in effect. After the first year, the ISO ~~and the Market Advisor~~ 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 4.6.4.1 of the Market Monitoring Plan.

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## **8.0 Reinstating Performance Charges**

The ISO will monitor, on a real-time hourly or daily basis, as appropriate, its compliance with the standards established by NERC and NPCC and with the standards of Good Utility Practice for Control Performance, area control error, disturbance control standards, reserve pickup performance and system security. Should it appear to the ISO that degradation in performance threatens compliance with one or more of the established standards for these criteria or compromises reliability, and that reinstating the performance charges that were originally part of the ISO's market design, would assist in improving compliance with established standards for these criteria, or would assist in re-establishing reliability, the ISO may require Suppliers of Regulation Service, as well as Suppliers not providing Regulation Service, to pay a performance charge. Any reinstatement of Regulation penalties pursuant to this Section shall not override previous Commission-approved settlement agreements that exempt a particular unit from such penalties. The ISO shall provide notice of its decision to reinstate performance charges to the Commission, to each Customer and to the Operating Committee and the Business Issues Committee no less than seven days before it re-institutes the performance charges.

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If the ISO determines that performance charges are necessary, Suppliers of Regulation Service shall pay a performance charge per interval to the ISO as follows:

$$\text{Performance Charge} = \text{Energy Deviation} \times \text{MCP}_{\text{reg}} \times (\text{Length of Interval}/60 \text{ minutes})$$

Where:

Energy Deviation (in MW) is the absolute difference between the actual Energy supplied by the Supplier and the Energy required by the AGC Base Point Signals, whether positive or negative, averaged over each RTD interval; and

$\text{MCP}_{\text{reg}}$  is the market clearing price (\$/MW) which applies to the RTD interval for this Service in the Real-Time Market or the Day-Ahead Market, if appropriate.

The method used by the ISO to calculate the Energy Deviation will permit Suppliers a

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

#### **9.0 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(A) of this ISO Services Tariff, the ISO will suspend Generators' obligation to follow the AGC Base Point Signals sent to Regulation Service providers, freeing them to provide Energy

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and will suspend the real-time Regulation Service market. The ISO will not procure any Regulation Service and will establish a real-time Regulation Service market clearing price of zero for settlement and balancing purposes. The ISO will resume sending AGC Base Point Signals and restore the real-time Regulation Service market as soon as possible after the end of the reserve or maximum generation pickup.

### **Rate Schedule "3-A"**

#### **Charges Applicable to Suppliers That Are Not Providing Regulation Service**

##### **1.0 Persistent Undergeneration Charges**

A Supplier, other than a Supplier included in subsection 3.03 of this section, that is not providing Regulation Service and that persistently operates at a level below its schedule 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:

$$\text{Persistent undergeneration charge} = \text{Energy Difference} \times \text{MCP}_{\text{reg}} \times \text{Length of Interval} / 60 \text{ Minutes}$$

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; and

$MCP_{reg}$  is the market clearing price (\$/MW) which applies to the dispatch interval for which Regulation Service in the Real-Time Market, or, if applicable, the Day-Ahead Market.

### **1.01 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:

Overgeneration charge = Energy Difference x  $MCP_{reg}$  x Length of Interval/60 Minutes

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; and

$MCP_{reg}$  is the market clearing price (\$/MW) which applies to the dispatch interval for Regulation Service in the Real-Time Market, or, if applicable, the Day-Ahead Market.

## **2.0 Restoration of Performance Charges**

The persistent undergeneration charges described in Section 1.0 above shall be suspended in the event that the ISO re-institutes Regulation performance charges pursuant to Section 8.0 of Rate Schedule 3 of this Services Tariff. If the ISO re-institutes performance charges then Suppliers that sell Energy through the LBMP Markets or that supply Bilateral Transactions that serve Load in the NYCA, but do not provide Regulation Service, shall pay a performance charge per interval to the ISO as follows:

Performance Charge = Energy Difference x  $MCP_{reg}$  x Length of SCD Interval/60  
minutes

Where:

Energy Difference (in MW) is the absolute difference between the actual Energy supplied by the Supplier and the Energy is directed to produce by its RTD Base Point Signals, whether positive or negative, averaged over each RTD interval; and

$-MCP_{reg}$  is the market clearing price (\$/MW) which

applies to the interval for which Regulation Service was provided in the Real-Time Market, or, if appropriate, the Day-Ahead Market.

In cases in which the Energy Difference that would be calculated using the procedure described above is less than the tolerance set forth in the ISO Procedures, the ISO shall set the Energy Difference for that interval equal to zero.

### **3.0 Exemptions**

The following types of Generator shall not be subject to persistent undergeneration charges, or, if they are restored by the ISO, to performance charges:

- (i) Generators 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;
- (ii) 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 499 MW of such units;
- (iii) Intermittent Power Resources that depend on wind as their fuel and Limited Control Run of River Hydro Resources within the NYCA in operation on or before November 18, 1999, plus up to an additional 3300 MW of such Generators;

- (iv) Intermittent Power Resources that depend on landfill gas or solar energy as their fuel;
- (v) Capacity Limited Resources and 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;
- (vi) 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
- (vii) Generators operating during a Testing Period.

For Generators and Resources described in subsections (i), (ii), (iii), (iv) and (v) 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.

New York Independent System Operator, Inc.  
FERC Electric Tariff  
Original Volume No. 2

Original Sheet Nos. 282 through 285

Sheet Nos. 282 through 285 are reserved for future use.

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FERC Electric Tariff  
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Sched. 4

Second Revised Sheet No. 286  
Superseding First Revised Sheet No. 286

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.

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## **1.0 General Responsibilities and Requirements**

### **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. These quantities shall be established under Section 7.0 of this Rate Schedule. 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 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 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, 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 select Suppliers of Operating Reserves products to meet these requirements, including the locational Operating Reserves requirements, as part of its overall co-optimization process.

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

## **1.2 Supplier Eligibility Criteria**

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

- a. 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).

**b. 10-Minute Non-Synchronized Reserve:** Off-line Generators that are capable of starting, synchronizing, and increasing their output level within ten (10) minutes and that meet the criteria set forth in the ISO Procedures, and, Demand Side Resources that are capable of reducing their Energy usage within ten (10) minutes and that meet the criteria set forth in the ISO Procedures, shall be eligible, to supply 10-Minute Non-Synchronized Reserve.

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

**d. Self-Committed Fixed and ISO-Committed Fixed Generators:**

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

**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 that are selected to provide Operating Reserve in the Day-Ahead Market or any supplemental commitment may not increase their Energy Bids or Demand Reduction Bids for portions of their Resources that have been scheduled through those processes, or reduce their commitments, in real-time except to the extent that they are directed to do so by the ISO. Generators and Demand Side Resources may enter into alternate sales arrangements utilizing any Capacity that has not been scheduled to provide Operating Reserve.

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## **2.0 General Day-Ahead Market Rules**

### **2.1 Bidding and Bid Selection**

Resources capable of providing Spinning Reserve, 10-Minute Non-Synchronized Reserve and/or 30-Minute Reserve in the Day-Ahead commitment may submit Availability Bids for each hour of the upcoming day. If a Supplier offers Resources that are capable, based on their indicated commitment status, of providing Operating Reserves but does not submit an Availability Bid, its Day-Ahead Bid will be rejected in its entirety. A Supplier may resubmit a complete Day-Ahead Bid, provided that the new bid is timely.

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

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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 UOLN or UOLE, whichever is applicable.

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.

## **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.

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### **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, 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 6.2 of this Rate Schedule. The only restriction on Suppliers' ability to exercise this option is that all Suppliers with Day-Ahead Operating Reserves schedules must make the scheduled amount of Capacity available to the ISO for dispatch in the RTD if the ISO initiates a Supplemental Resource Evaluation.

### **3.0 General Real-Time Market Rules**

#### **3.1 Bid Selection**

The ISO will automatically select Operating Reserves Suppliers in real-time from eligible Resources, that submit Real-Time Bids pursuant to

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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 Resource's emergency response rate multiplied by ten; (ii) for 10-Minute Non-Synchronized Reserves, or for non-synchronized 30-Minute Reserves, the Resource's UOL<sub>N</sub> or UOL<sub>E</sub>, whichever is applicable at the relevant time (the Resource may offer one product or the other depending on the time required for it to start-up and synchronize to the grid); and (iii) for synchronized 30-Minute Reserves, the Resource's emergency response rate multiplied by twenty. However, the sum of the amount of Energy or 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<sub>N</sub> or UOL<sub>E</sub>, whichever is applicable.

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

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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 specified above.

### **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.

### **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.

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### **3.4 Activation of Operating Reserves**

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

### **3.5 Performance Tracking and Supplier Disqualifications**

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

### **3.6 Performance Index for Demand Side Resource Suppliers of Operating Reserves**

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

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

each interval in which the ISO has instructed the Demand Side Resource to convert its Operating Reserves to Demand Reduction the Performance Index shall be calculated pursuant to the following formula, provided however when UAGi is zero or less, the Reserve PI shall be set to zero:

$$\text{Reserve PI} = \text{Min} \left[ \left( \text{UAGi} / \text{ADGi} + .1 \right), 1 \right]$$

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

#### **4.0 Operating Reserves Settlements - General Rules**

##### **4.1 Establishing Locational Reserve Prices**

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

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of three locations: (i) West of Central-East (“West” or “Western”); (ii) East of Central-East excluding Long Island; and (iii) Long Island (“L.I.”). The ISO will thus calculate nine different locational Operating Reserve prices in both the Day-Ahead Market and the Real-Time Market. Day-Ahead locational reserve prices shall be calculated pursuant to Section 5.0 of this Rate Schedule. Real-Time locational reserve prices shall be calculated pursuant to Section 6.0 of this Rate Schedule

#### **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 the East. The ISO will calculate separate locational Long Island Operating Reserves prices but will not post them or use them for settlement purposes.

#### **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,

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and the substitution of a higher quality for the lower quality product does not cause locational Operating 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. 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.

## **5.0 Operating Reserve Settlements – Day-Ahead Market**

### **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 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:

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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 L.I. 30-Minute Reserves = SP1 + SP4 + SP7

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

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

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 or L.I. 30-Minute Reserve requirement constraint for the hour

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

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

SP7 = Shadow Price for Long Island 30-Minute Reserve requirement constraint for the hour

SP8 = Shadow Price for Long Island 10-Minute Reserve requirement constraint for the hour

SP9 = Shadow Price for Long Island Spinning Reserve requirement constraint for the hour

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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

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during the fifth SCUC pass described in Section I.B of Attachment B to this Services Tariff, and Section I.B of Attachment J to the ISO OATT. 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 7.0 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.

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## **5.2 Other Day-Ahead Payments**

As is provided in Section 4.10 and Attachment C of this ISO Services Tariff, the ISO shall compensate each ISO-Committed Flexible Generator providing Operating Reserves if its Bid Production Cost to provide the Energy and Ancillary Services it is scheduled to supply in the Day-Ahead Market, including start-up costs, minimum Load costs, and Availability Bids, exceeds the revenues it receives from the sale of Energy and Ancillary Services. As is provided in Attachment C of this ISO Services Tariff, the ISO shall compensate ISO-Committed Demand Side Resources providing Operating Reserves if their Bids to provide Operating Reserves scheduled in the Day-Ahead Market exceed the revenues received from the sale of Operating Reserves and from any margin earned on the sale of Regulation Service in the Day-Ahead Market settlement.

## **6.0 Operating Reserve Settlements – Real-Time Market**

### **6.1 Calculation of Real-Time Market Clearing Prices**

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

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

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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 L.I. 30-Minute Reserves = SP1 + SP4 + SP7

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

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

Where:

SP1 = Shadow Price for total 30-Minute 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 or L.I. 30-Minute Reserve requirement constraint for the  
interval

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

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

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SP7 = Shadow Price for Long Island 30-Minute Reserve requirement constraint for the interval

SP8 = Shadow Price for Long Island 10-Minute Reserve requirement constraint for the interval

SP9 = Shadow Price for Long Island Spinning Reserve requirement constraint for the interval

Real-time locational Shadow Prices will be calculated by the ISO's RTD. Each Real-Time Shadow Price for each Operating Reserves 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 third RTD pass described in Section I.A.1.b.iii of Attachment B to this ISO Services Tariff, and Section I.A.1.b.iii of Attachment J to the ISO OATT. As a result, the Shadow Price for each Operating Reserves 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 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 described in Section 7.0 of this Rate Schedule, which will

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

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

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

**A. During Intervals When Scarcity Pricing Rule “A” Applies**

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

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

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

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

The Western Spinning Reserve market clearing price shall be the higher of: (i) the highest Lost Opportunity Cost of any provider of Western Spinning Reserve or Western synchronized 30- Minute Reserves that is scheduled by RTD; and (ii) the original market clearing price calculated under Section 6.1 above.

The Western 10-Minute Non-Synchronized Reserve market clearing price shall be the higher of: (i) the highest Lost Opportunity Cost of any provider of Western synchronized 30 Minute-Reserve that is scheduled by RTD; and (ii) the original market clearing price calculated under Section 6.1 above.

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The Western 30-Minute Reserve market clearing price shall be the higher of: i) the highest Lost Opportunity Cost of any provider of Western synchronized 30-Minute Reserve that is scheduled by RTD; and (ii) the original market clearing price calculated under Section 6.1 above.

**B. During Intervals When Scarcity Pricing Rule “B” Applies**

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

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

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

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

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

## **6.2 Operating Reserve Balancing Payments**

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

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

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

### **6.3. Other Real-Time Payments**

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

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

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

## **7.0 Operating Reserve Demand Curves**

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

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

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The ISO Procedures shall establish and post a target level for each 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. 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 requirement, the price on the total Spinning Reserves demand curve shall be \$500/MW. For all other quantities, the price on the total Spinning Reserves demand curve shall be \$0/MW.

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

(c) 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 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.

(d) 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 requirement, the price on the total 10-minute reserves demand curve shall be \$150/MW. For all other quantities, the price on the total 10-minute reserves demand curve shall be \$0/MW.

(e) Eastern or Long Island 10-Minute Reserves. For quantities of Operating Reserves meeting the Eastern or Long Island 10-minute reserves requirement that are less than or equal to the target level for that requirement, the price on the Eastern or Long Island 10-minute reserves demand curve shall be \$500/MW. For all other quantities, the price on the Eastern or Long Island 10-Minute Reserves demand curve shall be \$0/MW.

(f) 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 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.

(g) 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 requirement minus 400 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 requirement minus 200 MW but that exceed the target level for that requirement minus 400 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 requirement but that exceed the target level for that requirement minus 200 MW, the price on the total 30-Minute Reserves demand curve shall be \$50/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.

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

(i) 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 requirement, the price on the Long Island 30-Minute Reserves demand curve shall be \$300/MW. For all other quantities, the price on the Long Island 30-Minute Reserves demand curve shall be \$0/MW.



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 7.0 is in effect. After the first year, the ISO ~~and the Market Advisor~~ 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.

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 4.6.4.2 of the Market Monitoring Plan.

## **8.0 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) supplying any one of the Operating Reserves under ISO control. The Generator(s) must meet ISO rules for acceptability. The amount that any such Customer will be

charged for Operating Reserves will be reduced by the market value of the services provided by the specified Generator(s) as determined in the ISO Services Tariff.

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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New York Independent System Operator, Inc.  
FERC Electric Tariff  
Original Volume No. 2

Original Sheet Nos. 308 through 310

Sheets Nos. 308 through 310 are reserved for future use.

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## **Rate Schedule 5**

### **Payments and Certain Charges For Black Start and System Restoration Services**

This Rate Schedule applies to payments to Generators who provide Black Start and System Restoration Services to transmission facilities that are part of the ISO's Black Start and System Restoration plan (the ISO Plan"); to payments to existing Generators of such services that are part of Transmission Owners' individual Black Start and System Restoration Services plans for their Transmission Districts; and to charges for such services that are allocated to Transmission Customers in the Consolidated Edison Company of New York, Inc.'s ("Consolidated Edison") Transmission District.

#### **1.0 Requirements**

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

The full restoration of the NYS Power System may require additional Black Start

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

**2.0 Payment to Generators Under the Black Start and System Restoration Services Plans Developed by the ISO and by Individual Transmission Owners Except for Existing Generators Under the Consolidated Edison Plan**

By May 1<sup>st</sup> of each year, Generators which were selected to provide Black Start and System Restoration Services under the Black Start and System Restoration Services plans developed by the ISO and by individual Transmission Owners, except for existing Generators within the Consolidated Edison Transmission District, 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 Black Start and System Restoration Services capability;
- Annual costs associated with training operators in Black Start and System Restoration Services; and
- Annual costs associated with Black Start and System Restoration Services testing in accordance with the ISO Plan or the plan of an individual Transmission Owner.

Each Generator will be paid on the basis of its costs filed with the ISO. The daily rate for Black Start and System Restoration Services 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 Black Start and System Restoration Services shall conduct 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 Black Start and System Restoration Services payments and that fails a test shall forfeit all payments for such services since its last successful test. Payments to that Generator shall not resume until it successfully passes the test.

**3.0 Payments to and Charges for Existing Generators Providing Black Start and System Restoration Services Under the Consolidated Edison Transmission District**

Generators that are in-service as of October 1, 2005 and are listed in the Consolidated Edison Black Start and System Restoration Services plan filed with the ISO as of that date shall be paid for those services in accordance with Section 3.1 below. Charges to fund such payments shall be allocated among Transmission Customers in the Consolidated Edison Transmission District under Section 3.2 below. Generators that are in service as of October 1, 2005 and are listed in the Consolidated Edison Black Start and System Restoration Services plan are deemed to have satisfied testing requirements for the testing period that ends April 30, 2005.

**3.1 Payments to Existing Generators Under the Consolidated Edison Plan**

Existing Generators shall be eligible for Black Start and System Restoration Services payments, provided that they: (i) successfully test all necessary equipment in compliance with the Consolidated Edison testing criteria that are included in the ISO Procedures and provided that the testing criteria conform to Appendix I to this Rate Schedule; and (ii) commit to be available to provide these services for an initial minimum period of three years. At the end of the second year of the initial three year period a Generator, or Consolidated Edison, may give notice that the Generator will no longer be part of the Consolidated Edison Black Start and System Restoration Services plan, effective at the end of third year. For subsequent periods, each Generator, or Consolidated Edison, may give one year's advance notice at the end of every subsequent two year-period, that the Generator will no longer be part of the Consolidated Edison plan, so that a rolling three-year commitment is maintained.

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Eligible existing Generators in the Consolidated Edison Transmission District shall receive annual compensation for providing Black Start and System Restoration Services based on unit type and the level of their interconnection to the New York State Transmission System pursuant to the following table.

	<b>Steam Turbine</b>	<b>Gas Turbine</b>
345 kV	\$350,000/yr/unit	\$350,000/yr/site
138 kV	\$300,000/yr/unit	\$300,000/yr/site

These annual amounts will be paid to existing Generators in twelve equal monthly payments. The monthly payments shall also include compensation for legitimate, verifiable, and adequately documented operator training costs associated with readiness to provide Black Start Service and System Restoration Services, and for legitimate, verifiable, and adequately documented variable costs associated with annual tests of Black Start and System Restoration Services capability, that existing Generators invoice to the ISO, subject to the ISO's independent review.

Eligible existing Generators shall conduct annual Black Start and System Restoration Services capability tests and shall ensure that all relevant personnel are trained in black start and restoration operations. Detailed information about the tests and training standards shall be set forth in the ISO Procedures, which shall incorporate criteria developed by Consolidated Edison.

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The core features of the testing criteria are included in this ISO Services Tariff as Appendix I to this Rate Schedule and the ISO Procedures may not be revised in a manner that creates an inconsistency between them and Appendix I. Upon successful completion of a test, a Generator shall submit a certification form to the ISO in the form provided in Appendix II to this Rate Schedule. If a Generator fails a Black Start and System Restoration Services capability test, it shall be subject to a *pro rata* reduction in its annual payments based on the elapsed time between the unsuccessful test and a subsequent successful test.

The ISO shall also reimburse existing Generators for equipment damage that the ISO reasonably finds: (1) to have resulted from operating such equipment in response to operational orders from the ISO, or Consolidated Edison, pursuant to the ISO Services Tariff or the ISO OATT, (2) that reasonably available and customary insurance was not available for the damages incurred and (3) would not have occurred but for the Generator's provision of Black Start and System Restoration Services. Further, the ISO shall reimburse the owners of the Astoria Station steam units 3, 4 and 5 and Astoria Station gas turbines 4-3 and 4-4 for equipment upgrades that the ISO reasonably finds are needed to minimize the risk of equipment damage at the Astoria Station site in the Consolidated Edison Transmission District. The burden of making such showings will be upon the owners of the specified Generators. Any such reimbursement shall be made available for review by the Commission upon request by a Market Participant.

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**3.2 Charges to Support Payments to Existing Generators Under the Consolidated Edison Plan**

The ISO shall collect, on a monthly basis, a charge from each Transmission Customer in the Consolidated Edison Transmission District in order to fund the payments described above in Section 3.1. The charge shall be equal to the product of (a) the Transmission Customer's hourly Load Ratio Share of Load in the Consolidated Edison Transmission District, and (b) the total payments for existing Black Start and System Restoration Services in that Transmission District under Section 3.1, divided by the total number of hours in the month.

**3.3 Payments to New Generators that Provide Black Start and System Restoration Services in the Consolidated Edison Transmission District**

New Generators that agree to provide Black Start and System Restoration Services within the Consolidated Edison Transmission District shall be treated as set forth in Section 2.0 above.

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**Rate Schedule 5. Appendix I**  
**Core Features Of Testing Criteria**  
**Black Start and Restoration Services Testing Requirements**  
**Consolidated Edison Transmission District**

**General**

1. Testing shall be performed annually, consistent with Consolidated Edison Company of New York, Inc. (“Consolidated Edison”) system operation requirements to qualify for Black Start and Restoration Services payments during the annual compensation period, which shall be May 1<sup>st</sup> through April 30<sup>th</sup>.
2. A test will be considered successful if it is completed in accordance with the written black start test procedures that have been adopted by the plant.

**Scheduling a Test**

1. The annual test period shall be November 1<sup>st</sup> to April 30<sup>th</sup>, and may be reasonably extended by mutual agreement among the plant owner, Consolidated Edison and the ISO, without financial penalty.
2. The test date must be agreed upon by Consolidated Edison, the plant owner and the ISO.
3. An annual black start test may be performed prior to a maintenance outage only if there is no other scheduling option within the test period.
4. If the annual test is unable to be completed during the test period due to a forced outage or

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force majeure event, Consolidated Edison and the plant owner will conduct the test outside the test period without a *pro rata* reduction in annual payments.

5. If a black start test is not successful, the plant owner will have a reasonable opportunity to reschedule and conduct a subsequent test.

### **Gas Turbine Facility Testing Requirements**

- ~~6~~1. A qualifying test of a gas turbine must be conducted when the unit is in a cold condition, i.e., the unit will be off line and will be brought on line specifically to conduct the black start tests.
2. The gas turbine-Generator units to be tested will be off line at the start of the test and will be isolated from all external Consolidated Edison light and power sources.
3. The black start test must demonstrate that (i) the designated black start unit can be started and can energize the isolated light and power bus; and (ii) that the light and power source is adequate for the purpose of bringing the other units on line. Part (ii) must be demonstrated by starting up an additional gas turbine from the light and power bus that has been energized through Part (i) of the test. Site specific appendices will be developed to reflect these general criteria.
4. Once isolated from Consolidated Edison's light and power, the gas turbine facility will have 90 minutes to ready the equipment and to request permission to synchronize the additional generating unit to a live bus on the Consolidated Edison transmission system. When

authorized by the Consolidated Edison System Operator, the gas turbine-generator will be asked to close its breaker. Once the gas turbine-generator unit has synchronized and closed its breaker onto the transmission bus, the test will be considered successful.

5. A maximum of two (2) Consolidated Edison System Operations or Engineering personnel are allowed to be onsite to witness the test. At its discretion, the ISO may have its representatives onsite to witness the test. If an ISO representative is not onsite, a representative from Consolidated Edison and the plant owner will initiate calls to ISO operations personnel to signal the start time, completion time and outcome of the test.
6. Upon successful completion of the test, the generator owner shall submit a certification form, the template of which shall be included in the ISO tariff, to the ISO and Consolidated Edison.
7. Consistent with past practice, plant owners will continue to test on a monthly basis their standby diesel generators, black start gas turbines and UPS/battery back up systems. If any of these critical systems are found to be non-operational or otherwise unavailable, the plant owner will notify Consolidated Edison and the ISO within 36 hours and provide a schedule for their repair and return to service.

### **Steam Turbine Facility Testing Requirements**

1. A qualifying test of a steam turbine must be conducted while the unit is in a hot condition, *i.e.*, the unit must be on line and firm to the system prior to the test. The plant owner, the ISO and Consolidated Edison shall agree on a schedule for this test. The agreed upon test date

shall be deemed firm as of 48 hours prior to the scheduled beginning of the test. A firm test may not be called off or deferred except (1) by the ISO, for system or local reliability reasons; or (2) if the unit is unable to be in hot condition because it was not selected by the ISO to run on the day prior to the test. As is the case for any ISO-approved outage, the plant owner shall not offer the unit into the Day Ahead Market for operation during the test the day, and such non-offering into the market shall be deemed not to diminish the unit's availability.

2. The steam unit will be required to start up using energy and voltage control from a gas turbine-generator to energize its internal light & power bus, and be ready to synchronize to an energized transmission system when directed by the Consolidated Edison System Operator.
3. A test shall be considered successful if, after isolation from the Consolidated Edison transmission system, the hot steam unit is synchronized to the transmission system in no more than 6 hours after the completion of the isolation and is firm to the system and operating at minimum load in no more than 82 hours after ~~closing its breaker~~ the completion of the isolation.
4. A maximum of two (2) Consolidated Edison System Operations or Engineering personnel will be allowed onsite to witness the test. ISO representatives may be onsite to witness the test. If an ISO representative is not onsite, a representative from Consolidated Edison and the plant owner will initiate calls to ISO operations personnel to signal the start time, completion time and outcome of the test.

5. Upon successful completion of the test, Consolidated Edison shall SRE the unit until midnight of the test day or until the unit's reference minimum run time has elapsed, whichever is earlier.
6. Upon successful completion of the test, the generator owner shall submit a certification form, the template of which shall be included in the ISO Services Tariff, to the ISO and Consolidated Edison.
7. Consistent with past practice, plant owners will continue monthly tests of standby diesel generators; black start gas turbines and UPS/battery back up systems. If any of these critical systems are found to be non-operational or otherwise unavailable, the plant owner will notify Consolidated Edison and the ISO within 36 hours and provide a schedule for their repair and return to service.

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## Rate Schedule 5. Appendix II

[Name of Generator Owner] hereby certifies that the [name/location of generation equipment] successfully performed a Black Start and System Restoration Services test on [date] in accordance with the ISO Procedures. [Name of Generator Owner] further certifies that it identifies and maintains a list of critical components in its black start facilities (e.g., batteries, diesel back-up generators, inverters etc.) and has performed tests to verify the condition of these critical components in accordance with good industry practice.

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*Signature of Officer*

Issued by: ~~Mark Lynch~~ Stephen G. Whitley, President  
Issued on: ~~December 9, 2005~~ February 25, 2010

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## **Rate Schedule 6**

### **Quick Start Reserves**

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

#### **1.0 Qualification to Provide Quick Start Reserves**

- 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.
- 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

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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.

## **2.0 Purchase and Selection of Quick Start Reserves and Associated Duties**

**2.1** When a Transmission Owner has issued confirmation pursuant to Section 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

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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.

- 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

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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.

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FERC Electric Tariff  
Original Volume No. 2  
Sched. 6

Substitute Original Sheet No. 319

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- 2.3** The ISO shall maintain complete and accurate records of all notices received by electronic mail or fax pursuant to Sections 2.1 and 2.2 of this Rate Schedule.
- 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

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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.

**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 2.1 of this Rate Schedule.

**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.

### **3.0 Duty to Produce Energy**

**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

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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.

**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.

#### **4.0 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 2.6 of this Rate

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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 5.1 of this Rate Schedule.

## 5.0 Payments to Suppliers; Payments by Load Serving Entities

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

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

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 (East) in the Day-Ahead Market
- $P_{30MR}$  = Price of 30-Minute Reserves (East) in the Day-Ahead Market
- Q = Quantity of MWs from the block of generator units accepted into the 30-Minute Reserves market.

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- 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.
- 5.3.** In addition to payments due to a Supplier of Quick Start Reserves pursuant to Section 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.
- 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 month the payment obligation is incurred. Amounts attributable to local reliability are those amounts incurred pursuant to Sections 2.1 and 3.1 of this Rate Schedule.

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## **6.0 Dispute Resolution**

**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 p

arty 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.

**6.2** Disputes other than those addressed pursuant to Section 6.1 of this Rate Schedule may be resolved through the ISO's Dispute Resolution Process.

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**Rate Schedule 7**  
**Charges for Wind Forecasting Service**

The ISO shall charge each Intermittent Power Resource that depends on wind 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 (“Wind Generators”), for Wind 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 monthly.

**1.0 Responsibilities**

The ISO shall calculate a wind forecasting charge which shall include a fixed component and a component that varies by the nameplate capacity of the Wind Generator. Such charge shall be based upon the costs the NYISO incurs in producing a forecast of the expected generation output of each Wind Generator subject to this charge.

**1.1 Wind Generators**

Wind Generators shall pay the charge for Wind Forecasting Service monthly.

**2.0 Charges**

The ISO shall assess the following wind forecasting charges monthly to each Wind Generator as of the effective date of these changes:

\$500.00 as a fixed fee and

\$7.50 / MW of name plate capacity