(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 to reduce the resource its real power (MW) output below its schedule 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 Resource supplying Voltage Support Service.

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

Where:

P_{RT} = Real-Time LBMP

D_1 = Original dispatch point

D_2 = New dispatch point

Rate Schedule 3

Payments for Regulation Service

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

1.0 Obligations of the ISO and Suppliers

1.1 The ISO shall:

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

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

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

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

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

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

(g) Monitor Generators' 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) Offer only Generators that are; (i) ISO-Committed Flexible or Self-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;

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

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

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

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

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

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

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

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

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

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

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

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

3.0 Monitoring Regulation Service Performance and Performance Related Payment Adjustments

(a) The ISO shall establish (i) Generator performance measurement criteria; (ii) procedures to disqualify Suppliers whose Generators 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.

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

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

4.0 Regulation Service Settlements - Day-Ahead Market

4.1 Calculation of Day-Ahead Market Clearing Prices

The ISO shall calculate a Day-Ahead Market clearing price for Regulation Service each hour of the following day. The Day-Ahead Market clearing price for each hour shall equal the Day-Ahead Shadow Price of the ISO's Regulation Service constraint for that hour, which shall be established under the ISO Procedures. Day-Ahead Shadow Prices will be calculated by the ISO's SCUC. Each hourly Day-Ahead Shadow Price shall equal the marginal Bid cost of scheduling Resources to provide additional Regulation Service in that hour, including any impact on the Bid Production Cost of procuring Energy or Operating Reserves that would result from procuring an increment of Regulation Service in that hour,, as calculated during the fifth SCUC pass described in Section I.B of Attachment B to this ISO Services Tariff, and Section I.B of Attachment J to the ISO OATT. As a result, the 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.

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 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.

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 and Lost Opportunity Costs of Generators scheduled to provide Regulation Service in real-time.

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

5.2 Real-Time Regulation Service Balancing Payments

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

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

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

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

5.3 Other Real-Time Regulation Service Payments

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

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

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

5.4 Performance-Based Adjustments to Regulation Service Payments

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

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

Where:

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

Where:

PI is the Generator's performance index; and

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

6.0 Energy Settlement Rules for Generators Providing Regulation Service

6.1 Energy Settlements

For any interval in which a Generator is providing Regulation

Service, it shall receive a settlement payment for Energy consistent with a real-time Energy injection equal to the lower of its actual generation or its AGC Base Point Signal.

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

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

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

Where:

s is the number of seconds in the RTD interval;

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

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

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

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

Where:

s is the number of seconds in the RTD interval;

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

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.

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 when it conducts this investigation.

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

Not later than 90 days after the implementation of the Regulation Service

Demand Curve the ISO, in consultation with its Advisor, shall conduct an initial review in accordance with the ISO Procedures. The scope of the review shall be upward or downward in order to optimize the economic efficiency of any, or all, the ISO-Administered Markets. The ISO and the Market Advisor shall perform additional quarterly reviews, subject to the same scope requirement, during the remainder of the first year that this Section 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.

Reserved for Future Use.

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.

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:

Performance Charge = Energy Deviation x MCP_{reg} x (Length of Interval/60 minutes)

Where:

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

MCP_{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 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 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 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. Persistent undergeneration charges per interval shall be calculated as follows:

Persistent undergeneration charge = Energy Difference x MCP_{reg} x Length of Interval/60 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.

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 365 MW of such units;

(iii) Existing intermittent (i.e., non-schedulable) renewable resource Generators within the NYCA in operation on or before November 18, 1999, plus up to an additional 500 MW of such Generators; and

Filed to comply with order of the Federal Energy Regulatory Commission, Docket No. ER04-230-000, et. al., issued February 11, 2004, 106 FERC ¶ 61,111 (2004).

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.

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 Generators or Demand Side Resources are eligible to supply particular Operating Reserve

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

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

c. **30-Minute Reserve**: (i) Generators that are ISO-Committed Flexible or Self-Committed Flexible and operating within the dispatchable portion of their operating range shall be eligible to supply synchronized 30-Minute Reserves; (ii) Off-line Generators that are capable of starting, synchronizing, and increasing their output level within thirty (30) minutes and that meet the criteria set forth in the ISO Procedures, and when the ISO's software can support their provision of this product. 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.

2.0 General Day-Ahead Market Rules

2.1 Bidding and Bid Selection

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

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

However, the sum of the amount of Energy or Demand Reduction each Resource is scheduled to provide, the amount of Regulation Service it is scheduled to provide, and the amount of each Operating Reserves product it is scheduled to provide shall not exceed its UOL_N or UOL_E, whichever is applicable.

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.

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

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

3.0 General Real-Time Market Rules

3.1 Bid Selection

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

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

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

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

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 selected to supply Operating Reserves is activated, the ISO shall measure and track its actual Energy production against its expected performance in real-time. The ISO may disqualify Suppliers that consistently fail to provide Energy 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.

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 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, 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:

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

Day-Ahead locational Shadow Prices will be calculated by SCUC. Each hourly Day-Ahead Shadow Price for each Operating Reserves requirement shall equal the marginal Bid cost of scheduling Resources to provide additional Operating Reserves to meet that requirement in that hour, including any impact on the Bid Production Cost of procuring Energy or Regulation Service that would result from procuring an increment of Operating Reserve to meet the requirement in that hour, as calculated during the fifth SCUC pass described in Section 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.

5.2 Other Day-Ahead Payments

As is provided in Section 4.10 and Attachment C of this ISO Services Tariff, the ISO shall compensate each ISO-Committed Flexible Resource 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.

6.0 Operating Reserve Settlements – Real-Time Market

6.1 Calculation of Real-Time Market Clearing Prices

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

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

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

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 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.

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.

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.

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

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

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

6.2 Operating Reserve Balancing Payments

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

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

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

6.3. Other Real-Time Payments

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

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

Finally, whenever a Resource's real-time Operating Reserves schedule is reduced by the ISO to a level lower than its Day-Ahead schedule for that product, the Resource's 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.

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.

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

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

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

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.