BPCG, DAMAP and Related Tariff Provisions
September 14, 2009
MIWG

Double Underlined Language has been added to the version circulated to the July 30, 2009 MIWG ; language stricken from the version distributed to the July 30, 2009 MIWG appears with strikethrough

BPCG and Related Tariff Provisions[1]

Definitions (Services Tariff)

Eighth Revised Sheet No. 28

2.15b Bid Production Cost Guarantee ("BPCG")
A payment made in accordance with Section 4.10 and Attachment C of this ISO Services Tariff.

Seventh Revised Sheet No. 33A

2.36a Day-Ahead Margin
That portion of Day-Ahead LBMP, Operating Reserves settlement or Regulation Services settlement for an hour that represents the difference between the Supplier's accepted Day-Ahead offer price and the Day-Ahead LBMP, Operating Reserves settlement or Regulation Service settlement for that hour.

2.36b Day-Ahead Margin Assurance Payment
A supplemental payment made to an eligible Supplier that buys out of a Day-Ahead Energy, Regulation Service, or Operating Reserves schedule such that an hourly balancing payment obligation offsets ~~in a manner that offsets~~ its Day-Ahead Margin. Rules for calculating these payments, and for determining Suppliers' eligibility to receive them, are set forth in Attachment J of this ISO Services Tariff.

Fifth Revised Sheet No. 35

2.44 Dispatch Day
The twenty-four (24) hour (or, if appropriate, the twenty-three (23) or twenty-five (25) hour) period commencing at the beginning of each day (0000 hour).

2.46 Economic Operating Point

A point on the eleven constant cost steps that comprise a Supplier's Incremental Energy Bid for a Resource, established pursuant to the ISO Procedures, that is a function of: i) the Real-Time LBMP at the Resource [Supplier's] bus; ii) the Supplier's Incremental Energy Bid for a Resource; and iii) when the Real-Time LBMP at the Resource bus equals the Supplier's Incremental Energy Bid for a Resource, the Real-Time Scheduled Energy Injection. The [A Supplier's] Economic Operating Point for a Supplier's Resource may be above, below, or equal to its Real-Time Scheduled Energy Injection.

Import Curtailment Guarantee Payment

A payment made in accordance with Section 4.5.C(2) and Attachment J of this ISO Services Tariff to compensate a Supplier whose Import is Curtailed by the ISO.

Sixth Revised Sheet No. 58

2.137 Performance Tracking System

A system designed to report~~provide quantitative comparisons of~~ actual and scheduled metrics ~~values versus expected and forecasted values~~ for Generators and Loads. This system is ~~will be~~ used by the ISO to measure compliance with criteria associated with~~, but not limited to,~~ the provision of Energy and Ancillary Services~~Regulation Service~~.

Supplemental Event Interval

Any RTD interval in which there is a maximum generation pickup or a large event reserve pickup or which is one of the three RTD intervals following the termination of the maximum generation pickup or the large event reserve pickup; *provided, however*, that the three following RTD intervals will not be included in this determination to the extent that they occur in the next Dispatch Day.

Subzone: That portion of a Load Zone in a Transmission Owner's Transmission District

Services Tariff Body

(Excluding Section 4.10 of the Services Tariff)

Fourth Revised Sheet No. 87.01

4.1.7 Commitment of Generator for Reliability

Generatorsing ~~units~~ committed by the ISO for service to ensure NYCA or local system reliability will recover startup, incremental Energy, and minimum generation costs not recovered in the Dispatch Day. Payment for such costs shall be determined pursuant to the provisions of Section 4.10 and Attachment C of this ISO Services Tariff. Such payments shall be recovered by the ISO from the ~~local~~ customers for whose benefit the generation was committed in accordance with Rate Schedule 1 of the ISO OATT.

Original Sheet No. 91B

4.2.5 Reliability Forecast for the Six Days Following the Dispatch Day

In the SCUC program, system operation shall be optimized based on Bids over the Dispatch Day. However, to preserve system reliability, the ISO must ensure that there will be

First Revised Sheet No. 92

sufficient resources available to meet forecasted Load and reserve requirements over the seven (7)-day period that begins with the next Dispatch Day. The ISO will perform a Supplemental Resource Evaluation ("SRE") for days two (2) through seven (7) of the commitment cycle. If it is determined that a long start-up time Generator (*i.e.*, a Generator that cannot be scheduled by SCUC to start up in time for the next Dispatch Day) is needed for reliability, the ISO shall accept a Bid from the Generator and the Generator will begin its start-up sequence. During each day of the start-up sequence, the ISO will perform an SRE to determine if long start-up time Generators will still be needed as previously forecasted. ~~If the Generator is still needed, it will continue to accrue start-up cost payments on a linear basis.~~ If at any time it is determined that the Generator will not be needed as previously forecasted, the ISO shall order the Generator to abort its start-up sequence.~~, and its start-up payment entitlement will cease at that point.~~

The ISO will commit to long start-up time Generators to preserve reliability. However, the ISO will not commit resources with long start-up times to reduce the cost of meeting Loads that it expects to occur in days following the next Dispatch Day.

A Supplier that bids on behalf of a long start-up time Generator, including one that is committed and subsequently aborted by the ISO as described in this Section 4.2.5, may be eligible for a BPCG ~~Supplemental payments to these Generators, if necessary, will be determined~~ pursuant to the provisions of Section 4.10 and Attachment C of this ISO Services Tariff. The costs of such a BPCG ~~and~~ will be recovered by the ISO under Rate Schedule 1 of the ISO OATT.

The ISO shall perform the SRE as follows: (1) The ISO shall develop a forecast of daily system peak Load for days two (2) through seven (7) in this seven (7)-day period and add the appropriate reserve margin; (2) the ISO shall then

Sixth Revised Sheet No. 99A

A. RTD-CAM Modes

1. Reserve Pickup

The ISO will enter this RTD-CAM mode when necessary to re-establish schedules when large area control errors occur. When in this mode, RTD-CAM will send 10-minute Base Point Signals and produce schedules for the next ten minutes. RTD-CAM may also commit, or if

First Revised Sheet No. 99A.01

necessary de-commit, Resources capable of starting or stopping within 10-minutes. The ISO will continue to optimize for Energy and Operating Reserves, will recognize locational Operating Reserve requirements, but will suspend Regulation Service requirements. If Resources are committed or de-committed in this RTD-CAM mode the schedules for them will be passed to RTC and the Real-Time Dispatch for their next execution.

The ISO will have discretion to classify a reserve pickup as a "large event" or a "small event." In a small event the ISO will have discretion to reduce Base Point Signals in order to reduce transmission line loadings. The ISO will not have this discretion in large event. ~~As is explained in Section 4.10 below, t~~The distinction also has significance with respect to a Supplier's ~~Resources'~~ eligibility to receive BPCGs~~id Production Cost guarantee payments~~ in accordance with Section 4.10 and Attachment C of this ISO Services Tariff.

2. Maximum Generation Pickup

The ISO will enter this RTD-CAM mode when an Emergency makes it necessary to maximize Energy production in one or more location(s), i.e., Long Island, New York City, East of Central East and/or NYCA-wide. RTD-CAM will produce schedules directing all Generators located in a targeted location to increase production at their emergency response rate up to their UOL_E level and to stay at that level until instructed otherwise. Security constraints will be obeyed to the extent possible. The ISO will continue to optimize for Energy and Operating Reserves, will recognize locational Operating Reserve requirements, but will suspend its Regulation Service requirements.

First Revised Sheet No. 99A.03

B. Calculating Real-Time LBMPs

When RTD-CAM is activated, except when it is in reserve pickup mode, ~~it shall calculate~~ *ex ante* Real-Time LBMPs will be calculated at each Generator bus, and for each Load Zone, every five minutes, in accordance with the procedures set forth above in Section 4.4.3B. When it is in reserve pickup mode, ~~RTD-CAM will calculate~~ *ex ante* Real-Time LBMPs will be calculated every ten minutes, but RTD-CAM shall otherwise follow the procedures set forth above in Section 4.4.3B. In addition, when RTD-CAM is activated, Suppliers ~~will~~ may be ~~calculate Bid Production Cost payments for~~ eligible for BPCGs ~~Generators~~ during large event, but not small event, reserve pickups and during maximum generation pickups in accordance with ~~. These payments are described in~~ Section 4.10~~, and in Rate Schedule 4,~~ and Attachment C of this ISO Services Tariff.

C. Posting Commitment Decisions

To the extent that RTD-CAM makes commitment and de-commitment decisions they will be posted at the same time as Real-Time LBMPs.

Section 4.5 (Services Tariff)

First Revised Sheet No. 102.00

subsection C(1). In addition, if the checkout failure occurred for reasons within the Supplier's or Transmission Customer's control it will be required to pay the "Financial Impact Charge" described below. The ISO's Market Monitoring and Performance Unit will determine whether the Transaction associated with an injection failed for reasons within a Supplier's or Transmission Customer's control.

If an Energy injection at a Proxy Generator Bus is determined to have failed for reasons within a Supplier's or Transmission Customer's control, the Financial Impact Charge will equal: (i) the difference computed by subtracting the actual real-time Energy injection from the amount of the Import scheduled by RTC; multiplied by (ii) the greater of the difference computed by subtracting the RTC price from the RTD price in the relevant interval, or zero.

If a Wheel Through fails for reasons within a Supplier's or Transmission Customer's control, the Financial Impact Charge will equal the sum of the Financial Impact Charge described in this subsection and the Financial Impact Charge described below in subsection D(2).

All Financial Impact Charges collected by the ISO shall be used to reduce the charges assessed under Rate Schedule 1 of this ISO Services Tariff. In the event that the Energy injections

Second Revised Sheet No. 102.01.01

scheduled by RTC_{15} at a Proxy Generator Bus are Curtailed at the request of the ISO then the Supplier or Transmission Customer that is subjected to the Curtailment, in addition to the charge for Energy Imbalance, shall be eligible to receive an Import Curtailment Guarantee Payment for its curtailed Import pursuant to Attachment J of this ISO Services Tariff.~~paid the product (if positive) of: (a) the Real-Time LBMP at the Proxy Generator Bus minus the higher of its real-time Bid and zero; and (b) the scheduled Energy injections minus the actual Energy injections at that Proxy Generator Bus for the dispatch hour.~~[2]

Second Revised Sheet No. 102.01

limited upper operating limit shall be equal to the product of: (a) the Real-Time price for Energy, Operating Reserve Service and Regulation Service; and (b) the Capacity Limited Resource's Day-Ahead schedule for each of these services minus the amount of these services that it has an obligation to supply pursuant to its ISO-approved schedule. When a Capacity Limited Resource's Day-Ahead obligation above its Capacity limited upper operating limit is balanced as

[2] The substance of this provision has been relocated to Attachment J of the ISO Services Tariff.

described above, any real-time variation from its obligation pursuant to its Capacity limited schedules shall be settled pursuant to the methodology set forth in the first paragraph of this subsection C.

For any day in which: (i) an Energy Limited Resource is scheduled to supply Energy, Operating Reserves ~~Service~~ or Regulation Service in the Day-Ahead Market; (ii) the sum of its schedules to provide these services exceeds its bid-in Normal ~~u~~Upper ~~o~~Operating ~~l~~Limit; (iii) the Energy Limited Resource requests a reduction for Energy limitation reasons; and (iv) the ISO ~~modifies~~ reduces the Energy Limited Resource's Day-Ahead Emergency ~~u~~Upper ~~o~~Operating ~~l~~Limit to a limit no lower than the Normal Upper Operating Limit;~~ the imbalance charge imposed upon the Energy Limited Resource shall be equal to the sum of its Energy, Operating Reserve Service and Regulation Service imbalances across all twenty four hours of the Energy day, multiplied by the Real-Time price for each service in each hour at its location~~ the Resource may ~~. However, if the total margin received by the Energy~~

Second Revised Sheet No. 102.02

~~Limited Resource for the twenty four hour day is less than its Day-Ahead margin than it shall~~ be eligible to receive a Day-Ahead Margin Assurance Payment pursuant to Attachment J of this ISO Services Tariff.

Section 4.9 (Services Tariff)

Seventh Revised Sheet No. 105

4.9 Day-Ahead Margin Assurance Payments

A Supplier that is scheduled in the Day-Ahead Market to provide Energy, Regulation Service, or Operating Reserves may be eligible to receive a Day-Ahead Margin Assurance Payment pursuant to Attachment J of this ISO Services Tariff.~~If an eligible Supplier is forced to buy out of a Day-Ahead Energy, Regulation Service or Operating Reserve schedule in a manner that reduces its Day-Ahead Margin, that Supplier shall receive a Day-Ahead Margin Assurance Payment. Such payments shall be calculated pursuant to Attachment J of this ISO Services Tariff.~~[3]

Fourth Revised Sheet No. 140A

The ISO shall pay Special Case Resources that cause a verified Load reduction, in response to an ISO request to perform due to a Forecast Reserve Shortage, an ISO declared Major Emergency State, or in response to an ISO request to perform made in response to a

[3] The substance of the deleted portion is addressed in Attachment J of the ISO Services Tariff.

request for assistance for Load relief purposes or as a result of a Local Reliability Rule, for such Load reduction, in accordance with ISO Procedures. Subject to performance verification, Special Case Resources shall be paid the zonal Real-Time LBMP for the duration of their verified Load reduction or four (4) hours, whichever is greater, in accordance with ISO Procedures, provided, however, Special Case Resource Capacity shall settle Demand Reductions, in the interval and for the capacity for which Special Case Resource Capacity has been scheduled Day-Ahead to provide Operating Reserves, Regulation Service or Energy, as being provided by a Supplier of Operating Reserves, Regulation Service or Energy.

A Supplier that bids a Special Case Resource may be eligible for a BPCG pursuant to Section 4.10 and Attachment C of this ISO Services Tariff.

~~In the event that a Special Case Resource's Minimum Payment Nomination for the number of hours of requested performance or the minimum four (4) hour period, whichever is greater, exceeds the LBMP revenue received, the Special Case Resource will be eligible for a Bid Production Cost Guarantee to~~

Original Sheet No. 140B

~~make up the difference, in accordance with Section 4.23 of this Services Tariff and ISO Procedures, provided, however, the ISO shall set to zero the Minimum Payment Nomination for Special Case Resource Capacity in each interval in which such Capacity was scheduled Day-Ahead to provide Operating Reserves, Regulation Service or Energy.~~

Transmission Owners that require assistance from distributed Generators larger than 100 kW and Loads capable of being interrupted upon

Section 4.10 (Services Tariff)

Seventh Revised Sheet No. 105

4.10 Bid Production Cost Guarantee ~~and Curtailment Initiation Cost~~ Payments

4.10.1 Day-Ahead BPCGs for Generators

The ISO shall determine ~~, on a daily basis,~~ if a~~ny~~ Supplier eligible under Section 2.1 of Attachment C of this ISO Services Tariff for a Day-Ahead BPCG ~~ISO-Committed Fixed or ISO-Committed Flexible Generator, other than a Limited Energy Storage Resource, or Customer that schedules imports, that is committed by the ISO in the Day-Ahead Market~~[4] will not recover its Day-Ahead Minimum Generation Bid, Start-Up Bid, and Incremental Energy Bid ~~Price~~ in the Day-Ahead Market through Day-Ahead LBMP revenues and net Day-Ahead Ancillary Services revenues for Voltage Support Service, Regulation Service, and synchronized Operating Reserves. Such determination shall be made for an entire Day-Ahead Market day, and such determination shall be made separately for each Generator. On the basis of such determination, the ISO shall pay a Day-Ahead BPCG to the Supplier pursuant to Section 2.0 of Attachment C of this ISO Services Tariff. ~~If~~

4.10.2 Day-Ahead BPCGs for Imports

The ISO shall determine if a Supplier supplying an Import and eligible under Section 3.1 of Attachment C of this ISO Services Tariff for a Day-Ahead BPCG will not recover its Day-Ahead Decremental Bid- through Day-Ahead LBMP revenues. Such determination shall be made for an entire Day-Ahead Market day and such determination shall be made separately for each Import transaction. On the basis of such determination, the ISO shall pay a Day-Ahead BPCG to the Supplier pursuant to Section 3.0 of Attachment C of this ISO Services Tariff.

Eight Revised Sheet No. 106

~~the sum of the Minimum Generation Bid, Start-Up Bid and the net Energy Bid Price over the twenty-four (24) hour day of such a Generator or Importer exceeds its Day-Ahead LBMP revenue over the twenty-four (24) hour day, then that Generator or Importer's Day-Ahead LBMP revenue may be augmented by a supplemental Day-Ahead Bid Production Cost guarantee payment calculated pursuant to the provisions of Attachment C to this ISO Services Tariff. However, the amount of the shortfall of such a Generator will be compared to the margin that the Generator receives from being scheduled to provide Ancillary Services that it can provide only if scheduled to operate. The Generator's Ancillary Service margin is equal to the revenue it would have received for providing these Ancillary Services prior to any reductions based on a failure to provide these services less its Bid to provide these services, if any. If, and only to the extent that, the shortfall exceeds these Ancillary Service margins, the Generator will receive a payment pursuant to the provisions of Attachment C to this ISO Services Tariff.~~

First Revised Sheet No. 106.00

~~Demand Side Resources committed Day-Ahead to provide non-synchronized Operating Reserves shall be treated the same as Generators with respect to the determination of supplemental payments.~~

4.10.3 Real-Time BPCGs for Generators in RTD Intervals Other than Supplemental Event Intervals

~~In addition, the ISO shall: (i) use Real-Time Market prices and schedules to calculate and pay real-time Bid Production Cost guarantee payments to ISO-Committed Flexible Generators and to Customers that schedule imports; provided however, no real-time Bid Production Cost guarantee payment shall be made to a Limited Energy Storage Resource; (ii) use RTD prices and schedules to calculate and pay real-time Bid Production Cost guarantee~~

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~~payments to any Self-Committed Flexible Generator if its self-committed minimum generation level does not exceed its Day-Ahead schedule at any point during the Dispatch Day; and (iii) use RTD prices and schedules to calculate and pay real-time Bid Production Cost guarantee payments for Minimum Generation Bids and Start-Up Bids to ISO-Committed Fixed Generators. All such payments shall be calculated in the manner described in Attachment C to this ISO Services Tariff. No such payments shall be made to Customers that schedule Exports or Wheels-Through.~~

~~Except as expressly noted in this Section 4.10, Self-Committed Flexible and Self-Committed Fixed Resources shall not be eligible to receive Bid Production Cost guarantee payments.~~

First Revised Sheet No. 106.02

~~Both Bid costs, and LBMP and Ancillary Services revenues received during NYISO authorized Start-Up, Shutdown or Testing Periods shall be excluded from the calculation of the daily Bid Production Cost guarantee payment.~~

The ISO shall determine if a Supplier eligible under Section 4.1 of Attachment C of this ISO Services Tariff for a real-time BPCG will not recover its real-time Minimum Generation Bid, Start-Up Bid, and Incremental Energy Bid through real-time LBMP revenues and net real-time Ancillary Services revenues for Voltage Support Service, Regulation Service, and Synchronized Operating Reserves. Such determination shall be made for an entire Dispatch Day (except for Supplemental Event Intervals). Such determination shall be made separately for each Generator. On the basis of such determination, the ISO shall pay a real-time BPCG to the Supplier pursuant to Section 4.0 of Attachment C of this ISO Services Tariff.

4.10.4 BPCGs for Generators for Supplemental Event Intervals

The ISO shall determine if a Supplier eligible under Section 5.1 of Attachment C of this ISO Services Tariff for a BPCG for a Supplemental Event Interval will not recover its real-time Minimum Generation Bid ~~Start-up Bid,~~ and Incremental Energy Bid through real-time LBMP revenues and net real-time Ancillary Services revenues for Voltage Support Service, Regulation Service, and Operating Reserves in that interval. Such determination shall be made separately for each Supplemental Event Interval, and such determination shall be made separately for each Generator. On the basis of such determination, the ISO shall pay a BPCG to the Supplier for a Supplemental Event Interval pursuant to Section 5.0 of Attachment C of this ISO Services Tariff.

~~An ISO-Committed Flexible Generator that is eligible to receive a Day-Ahead Bid Production Cost guarantee payment but that then self-commits in certain hours, thus becoming ineligible for a real-time Bid Production Cost guarantee payment, shall not be disqualified from receiving a Day-Ahead Bid Production Cost guarantee payment.[5] 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, for the duration of the large event reserve pickup or maximum generation pickup and the three RTD intervals following the termination of the large event reserve pickup or maximum generation pickup.[6] 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.[7]~~

4.10.5 Real-Time BPCGs for Imports

The ISO shall determine if a Supplier supplying an Import and eligible under Section 6.1 of Attachment C of this ISO Services Tariff for a real-time BPCG will not recover its real-time Decremental Bid through real-time LBMP revenues. Such determination shall be made for an entire Dispatch Day. Such determination shall be made separately for each Import transaction. On the basis of such determination, the ISO shall pay a real-time BPCG to the Supplier pursuant to Section 6.0 of Attachment C of this ISO Services Tariff.

4.10.6 BPCGs for Long Start-Up Time Generators that Are Aborted by the ISO Prior to their Dispatch

The ISO shall determine if a Supplier eligible under Section 7.1 of Attachment C of this ISO Services Tariff for a BPCG for a long start-up time Generator (*i.e.*, a Generator that cannot be scheduled by SCUC to start up in time for the next Dispatch Day) that is aborted by the ISO prior to its dispatch will not recover the portion of its real-time Start-Up Bid through real-time LBMP revenues that corresponds to the portion of its start-up sequence that it completed prior to being aborted. Such determination shall be made for an entire Dispatch Day, and such determination shall be made separately for each long start-up time Generator. On the basis of such determination, the ISO shall pay a BPCG to the Supplier pursuant to Section 7.0 of

Attachment C of this ISO Services Tariff.

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4.10.7 BPCGs for Demand Reduction in the Day-Ahead Market

The ISO shall determine~~, on a daily basis,~~ if a Demand Reduction Provider eligible under Section 8.1 of Attachment C of this ISO Services Tariff for a BPCG for Demand Reduction in the Day-Ahead Market ~~any Demand Reduction Provider committed to provide Energy by the ISO in the Day-Ahead Market~~ will not recover its Day-Ahead Curtailment Initiation Cost and its Day-Ahead Demand Reduction Bid ~~price~~ through Day-Ahead LBMP revenues. Such determination shall be made for an entire Day-Ahead Market day, and such determination shall be made separately for each Demand Side Resource. On the basis of such determination, the ISO shall pay a BPCG to the Demand Reduction Provider pursuant to Section 8.0 of Attachment C of this ISO Services Tariff. ~~If a Demand Reduction Provider's Curtailment Initiation Cost Bid plus its Demand Reduction Bid Price over the twenty-four (24) hour day exceeds its Day-Ahead LBMP revenue over the twenty-four (24) hour day, its Day-Ahead LBMP revenue may be augmented by a supplemental Bid Production Cost guarantee payment pursuant to the provisions of Attachment C.~~

4.10.8 BPCGs for Special Case Resources

The ISO shall determine~~, on a daily basis,~~ if a Supplier eligible under Section 9.1 of Attachment C of this ISO Services Tariff for a BPCG for a Special Case Resource ~~ny Special Case Resource committed by the ISO~~ will not recover its Minimum Payment Nomination through real-time LBMP revenues. Such determination shall be made for an entire Dispatch Day, and such determination shall be made separately for each Special Case Resource. On the basis of such determination, the ISO shall pay a BPCG to the Supplier pursuant to Section 9.0 of Attachment C of this ISO Services Tariff. ~~If a Special Case Resource's Minimum Payment Nomination over the period of requested performance, or four (4) hour period, whichever is greater, exceeds the LBMP revenue received as a Special Case Resource over that same period, its LBMP revenue may be augmented by a supplemental payment pursuant to the provisions of Attachment C, *provided however*, that the ISO shall set to zero the Minimum Payment Nomination for that amount of Special Case Resource Capacity in each interval that was scheduled Day-Ahead to provide Operating Reserves, Regulation Service or Energy.~~

~~Each Generator committed by the ISO in the Real-Time Market whose Real-Time LBMP payments for Energy produced are less than its Minimum Generation and Start-Up Bids to produce that Energy will be compensated by the ISO for the shortfall, in accordance with~~

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~~Attachment C.~~

~~The ISO shall recover supplemental payments and Demand Reduction Incentive Payments to Demand Reduction Providers pursuant to Rate Schedule 1 of its Open Access~~

~~Transmission Services Tariff, from all Loads excluding exports and Wheels Through on a zonal basis in proportion to the benefits received after accounting for, pursuant to ISO Procedures, Demand Reduction imbalance charges paid by Demand Reduction Providers pursuant to Section 4.4.5.~~

4.10.9 Day-Ahead BPCGs for Demand Side Resources Scheduled to Provide Synchronized Operating Reserves ~~and Regulation Service~~

The ISO shall determine if a Supplier that bids Demand Side Resources committed by the ISO to provide synchronized Operating Reserves ~~and Regulation Service~~ in the Day-Ahead Market will not recover its Day-Ahead synchronized Operating Reserves ~~and Regulation Service~~ Bid to provide the amount of synchronized Operating Reserves ~~and Regulation Service~~ that it was scheduled to provide. Such Supplier shall be ~~make a supplemental payment pursuant to the terms~~eligible under Section 10.1 of Attachment C to this ISO Services Tariff for a Day-Ahead BPCG ~~if any Demand Side Resource scheduled to provide synchronized Operating Reserves in the Day-Ahead Market will not recover its synchronized Operating Reserves offers through its Day-Ahead synchronized Operating Reserves revenues and Regulation Service margin~~.[8] Such determination shall be made for an entire Day-Ahead Market day, and such determination shall be made separately for each Demand Side Resource. On the basis of such determination, the ISO shall pay a BPCG to the Customer pursuant to Section 10.0 of Attachment C of this ISO Services Tariff.

4.10.10 Real-Time BPCGs for Demand Side Resources Scheduled to Provide Synchronized Operating Reserves ~~and Regulation Service~~

The ISO shall determine if a Supplier that bids Demand Side Resources committed by the ISO to provide synchronized Operating Reserves ~~and Regulation Service~~ will not recover its real-time synchronized Operating Reserves ~~and Regulation Service~~ Bid to provide the amount of synchronized Operating Reserves ~~and Regulation Service~~ that it was scheduled to provide. Such Supplier shall be ~~make a supplemental payment pursuant to the terms~~ eligible under Section 11.1 of Attachment C to this ISO Services Tariff for a real-time BPCG~~if any Demand Side Resource scheduled to provide synchronized Operating Reserves in the Real-Time Market will not recover its synchronized Operating Reserves offers through its Real-Time synchronized Operating Reserves revenues and Regulation Service margin~~.[9] Such determination shall be made for an entire Dispatch Day, and such determination shall be made separately for each Demand Side Resource. On the basis of such determination, the ISO shall pay a BPCG to the Customer pursuant to Section 11.0 of Attachment C of this ISO Services Tariff.

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[8] This sentence was originally located in Section 4.10 of this ISO Services Tariff (Tariff Sheet 106).

[9] This sentence was originally located in Section 4.10 of this ISO Services Tariff (Tariff Sheet 106.02).

Second Revised Sheet No. 276.02

4.2 Other Day-Ahead Payments

A Supplier that bids on behalf of a Generator that provides Regulation Service may be eligible for a Day-Ahead BPCG pursuant to Section 4.10 and Attachment C of this ISO Services Tariff.~~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.~~ [NOTE: This duplicated a provisions on sheet 276.06 and was moved to Section 5.4]. . . <no changes to end of page>

Third Revised Sheet No. 276.05

5.3 Other Real-Time Regulation Service Payments

A Supplier that bids on behalf of a Generator that provides Regulation Service may be eligible for a BPCG pursuant to Section 4.10 and Attachment C of this ISO Services Tariff.~~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.~~

Third Revised Sheet No. 276.06

~~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.~~ [NOTE: This was moved to Section 5.4]

A Supplier that provides Regulation Service may also be eligible for a Day-Ahead Margin Assurance Payment pursuant to Section 4.9 and Attachment J of this ISO Services Tariff.

~~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.~~

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

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

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

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

~~s_i is the number of seconds in interval i; and~~

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

~~KPI = PI–PSF~~

~~1–PSF~~

~~Issued by: Elaine D. Robinson, Dir. Reg. Affairs Effective: May 24, 2008~~
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~~New York Independent System Operator, Inc.~~ ~~Second Revised Sheet No. 276A.01~~
~~FERC Electric Tariff~~ ~~Superseding First Revised Sheet No. 276A.01~~
~~Original Volume No. 2~~
~~Sched. 3~~

~~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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5.4 Payments and Performance-Based Adjustments to Payments for Regulation Service Providers~~ayments~~

Each Supplier that is scheduled in real-time to provide Regulation Service shall be paid in accordance with the following formula. 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~~.

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

Where:

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

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

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

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

s_i is the number of seconds in interval i; and

K_i 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:

$$K_i = (PI_i - PSF) / (1-PSF)$$

Where:

PI_i is the performance index of the Resource for interval i; 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. 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_i shall initially be set at 1.0 for Limited Energy Storage Resources.

No payments shall be made to any Supplier providing Regulation Service for any excess amount of Regulation Service beyond that 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.

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

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Sixth revised Sheet No. 294

~~**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 covert its Operating Reserves to Demand Reduction, the Performance Index shall have a value of one. For~~

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~~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:~~

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

~~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~~

Fifth Revised Sheet No. 297

5.2 Other Day-Ahead Payments

A Supplier that bids on behalf of (i) a Generator that provides Operating Reserves or (ii) a Demand Side Resource that provides Operating Reserves may be eligible for a Day-Ahead BPCG pursuant to Section 4.10 and Attachment C of this ISO Services Tariff.

~~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.~~

Seventh Revised Sheet No. 302

6.3. Other Real-Time Payments

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

A Supplier that bids on behalf of (i) a Generator that provides Operating Reserves or (ii) a Demand Side Resource that provides Operating Reserves may be eligible for a BPCG pursuant to Section 4.10 and Attachment C of this ISO Services Tariff.

~~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.~~

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A Supplier that provides Operating Reserves may also be eligible for a Day-Ahead

Margin Assurance Payment pursuant to Section 4.9 and Attachment J of this ISO Services Tariff.~~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.~~[10]

[10] The substance of the deleted language is addressed in Section 4.9 and Attachment J of this ISO Services Tariff.

Attachment C (Services Tariff)

Fourth Revised Sheet No. 421

ATTACHMENT C

~~FORMULAS FOR~~ DETERMINING BID PRODUCTION COST GUARANTEE PAYMENTS

1.0 INTRODUCTION

~~I. Supplemental Payments to Generators and Demand Resources~~

Ten ~~Three~~BPCGs ~~supplemental payments~~ for eligible Suppliers ~~Generators~~ are described in this attachment: (i) a Day-Ahead BPCG for Generators ~~Bid Production Cost guarantees~~; (ii) a Day-Ahead BPCG for Imports; (iii) -a r~~R~~eal-time BPCG for Generators~~Bid Production guarantees~~ ~~except for~~ ~~all~~ in RTD intervals other than Supplemental Event ~~i~~Intervals ~~except maximum generation pickups and large event reserve pickups~~; ~~and~~ (iv~~iii~~) a ~~Real-time~~ BPCG~~id Production Cost guarantees~~ for Generators -for Supplemental Event Intervals~~maximum generation pickups and large event reserve pickups~~; (v) a real-time BPCG for Imports; (vi) a BPCG for long start-up time Generators (*i.e.*, Generators that cannot be scheduled by SCUC to start up in time for the next Dispatch Day) that are aborted by the ISO prior to their dispatch; (vii) -a BPCG for Demand Reduction in the Day-Ahead Market; (viii) a Special Case Resources BPCG, (ix) a BPCG for Demand Side Resources providing synchronized Operating Reserves in the Day-Ahead Market, and (x) a BPCG for Demand Side Resources providing synchronized Operating Reserves in the Real-Time Market. –Suppliers~~Generators~~ shall be eligible for these payments in accordance with the eligibility requirements and formulas established in this Attachment C. ~~under the circumstances described in Article 4 and Rate Schedule 4 of this ISO Services Tariff.~~

The BPCGs described in this Attachment C are each calculated and paid independently from each other, such that a Customer's eligibility to receive one type of BPCG shall have no impact on the Customer's eligibility to receive another type of BPCG.

~~Demand Side Resources that are committed to provide non-synchronized Operating Reserves shall be treated the same as Generators with respect to the determination of supplemental payments.~~[11] ~~Demand Reduction Providers that provide Demand Reductions in the Day-Ahead Market shall be eligible for supplemental payments under Section II, but not this Section I. Demand Side Resources committed in the Day-Ahead market to provide synchronized Operating Reserves shall be eligible for supplemental payments under Section IV A. Demand Side Resources committed in the real-time market to provide synchronized Operating Reserves or Regulation Service shall be eligible for supplemental payments under Section IV B.~~

[11] Non-synchronized Operating Reserves are not eligible to receive a BPCG.

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2.0 ~~A.~~ DAY-AHEAD BPCGS~~id Production Cost Guarantee Formulas~~ FOR GENERATORS

2.1 Eligibility to Receive a Day-Ahead BPCG for Generators

(a) *Eligibility*.

A Supplier that bids on behalf of an ISO-Committed Fixed Generator or an ISO-Committed Flexible Generator that is committed by the ISO in the Day-Ahead Market shall be eligible to receive a Day-Ahead BPCG.

(b) *Non-Eligibility*.

Notwithstanding Section 2.1(a):

(i) a Supplier that bids on behalf of a Limited Energy Storage Resource shall not be eligible to receive a Day-Ahead BPCG; and

(ii) a Supplier shall not be eligible to receive a Day-Ahead BPCG under this Section 2.0 for an External Transaction.

2.2 Formulas for Determining Day-Ahead BPCGs for Generators~~.~~

(a) *Applicable Formula.* A Supplier's BPCG for a Generator g shall be as follows:

~~(i) if~~ $\cancel{T_{gh}^{DA}}$ ~~(as defined below) is equal to zero in that hour of that Day , then the Day-Ahead BPCG for Generator g shall be as calculated pursuant to Section 2.2(b);~~

~~(ii) if~~ $\cancel{T_{gh}^{DA}}$ ~~(as defined below) is greater than zero in that hour of that Day, but less than~~ $\cancel{EH_{gh}^{DA}}$~~, then the Day-Ahead BPCG for Generator g shall be as calculated pursuant to Section 2.2(c); and~~

~~(iii) if~~ $\cancel{T_{gh}^{DA}}$ ~~(as defined below) is greater than~~ $\cancel{EH_{gh}^{DA}}$~~, then the Day-Ahead BPCG for Generator g shall be zero.~~

~~(b) *Day-Ahead Bilateral Transactions*~~

Day-Ahead Bid Production Cost Guarantee for Generator g =

$$\max\left[\sum_{h=1}^{N}\left(\int_{\max(T_{gh}^{DA},\,EH_{gh}^{DA})}^{\max(T_{gh}^{DA},\,MGH_{gh}^{DA})} C_{gh}^{DA} + MGC_{gh}^{DA}\max\left(MGH_{gh}^{DA}-T_{gh}^{DA},0\right)+SUC_{gh}^{DA}\,NSUH_{gh}^{DA} - LBMP_{gh}^{DA}\max\left(EH_{gh}^{DA}-T_{gh}^{DA},0\right) - NASR_{gh}^{DA}\right),0\right]$$

~~(c) *Bilateral Transactions Less Than Day-Ahead Schedule*~~

~~Day-Ahead Bid Production Cost Guarantee for Generator g =~~

$$\cancel{\max\left[\sum_{h=1}^{N}\left(\int_{MGH_{gh}^{DA}}^{\max\left(T_{gh}^{DA},MGH_{gh}^{DA}\right)} C_{gh}^{DA} + MGC_{gh}^{DA}\min\left(\frac{T_{gh}^{DA}}{MGH_{gh}^{DA}},1\right) - LBMP_{gh}^{DA}\left(EH_{gh}^{DA}-T_{gh}^{DA}\right) - NASR_{gh}^{DA}\left(EH_{gh}^{DA}-T_{gh}^{DA}\right)\right),0\right]}$$

[12]

(b) *Variable Definitions.* The terms used in this Section 2.2 shall be defined as follows: ~~Where:~~

~~G — set of Generators;~~[13]

[12] In the Day-Ahead BPCG formulas, the variable "N" has been inserted in place of "24."

[13] The current Day-Ahead BPCG formula indicates that the NYISO should sum the outcome of the formula where the Generator at issue (g) is an element of the set of all Generators (G), but Attachment C is intended to calculate

N = number of hours in the Day-Ahead Market day;

T_{gh}^{DA} = Bilateral Transactions scheduled Day-Ahead to be sourced at Generator g in hour h expressed in terms of MWh;

EH_{gh}^{DA} = Energy scheduled Day-Ahead to be produced by Generator g in hour h expressed in terms of MWh;

MGH_{gh}^{DA} = Energy scheduled Day-Ahead to be produced by the minimum generation segment of Generator g in hour h expressed in terms of MWh;

C_{gh}^{DA} = Bid cost submitted by Generator g, or when applicable the mitigated Bid cost curve for Generator g, in the Day-Ahead Market for hour h expressed in terms of $/MWh;

MGC_{gh}^{DA} = Minimum Generation Bid by Generator g, or when applicable the mitigated Minimum Generation Bid for Generator g, for hour h in the Day-Ahead Market, expressed in terms of $/MWh;

SUC_{gh}^{DA} = Start-Up Bid by Generator g, or when applicable the mitigated Start-Up Bid for Generator g, in hour h in~~to~~ the Day-Ahead Market expressed in terms of $/start; *provided, however*, that:

> (i) the Start-Up Bid for Generator g, or when applicable the mitigated Start-Up Bid for Generator g, in hour h shall be reduced pro rata if Generator g fails to run for the number of hours for which it was scheduled to run in the Day-Ahead Market~~, unless the ISO~~ ~~economically scheduled Generator g to run in real time for the hour for which it was scheduled to run in the Day-Ahead Marke~~t For purposes of this pro rata reduction, the ISO shall consider the Generator to have run in any hour in which the ISO, in real-time, economically scheduled the Generator not to run. ;
>
> (ii) for a long start-up time Generator (*i.e.*, a Generator that cannot be scheduled by SCUC to start up in time for the next Dispatch Day) that is committed by the ISO and runs in real-time, the Start-Up Bid for Generator g in hour h shall be the Generator's Start-Up Bid, or when applicable the mitigated Start-Up Bid for Generator g, for the hour (as determined at the point in time in which the ISO provided notice of the request for start-up); and[14]

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the BPCG payable to a given Generator. For this reason, the symbols "Σ" and "g∈G" have been deleted from the start of the formulas, along with related variables.

[14] The Start-Up Bid variable has been modified to take into account long start-up time Generators whose Start-Up Bid is the hour in which the NYISO initially requested that the Generator begin its start-up sequence. See also

$NSUH_{gh}^{DA}$ = number of times Generator g is scheduled Day-Ahead to start up in hour h;

$LBMP_{gh}^{DA}$ = Day-Ahead LBMP at Generator g's bus in hour h expressed in $/MWh;

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$NASR_{gh}^{DA}$ = Net Ancillary Services revenue, expressed in terms of $, paid to Generator g as a result of having been committed to produce Energy for the LBMP Market and/or Ancillary Services Day--Ahead ~~to operate~~ in hour h is computed by summing the following: (1) Voltage Support Service payments received by that Generator for that hour, if it is not a Supplier of Installed Capacity and has been scheduled to operate in that hour; (2) Regulation Service payments made to that Generator for all Regulation Service it is scheduled Day-Ahead to provide in that hour, less that Generator's Day-Ahead Bid to provide that amount of Regulation Service in that hour (unless the Bid exceeds the payments that Generator receives for providing Regulation Service that was committed to produce Energy for the LBMP Market and/or Ancillary Services Day-Ahead, in which case this component shall be zero); and (3) payments made to that Generator for providing Spinning Reserve and synchronized 30-Minute Reserve in that hour if it is committed Day-Ahead to provide such reserves in that hour, less that Generator's Day-Ahead Bid to provide Spinning Reserve and synchronized 30-Minute Reserve in that hour.

3.0 DAY-AHEAD BPCGS FOR IMPORTS

3.1 Eligibility to Receive a Day-Ahead BPCG for Imports

A Supplier that bids an Import that is committed by the ISO in the Day-Ahead Market shall be eligible to receive a Day-Ahead BPCG.

3.2 BPCGs Calculated by Transaction ID

For purposes of calculating a Day-Ahead BPCG for an Import under this Section 3.0, the ISO shall treat the Import as being from a single Resource for all hours of the Day-Ahead Market day in which the same Transaction ID is used, and the ISO shall treat the Import as being from a different Resource for all hours of the Day-Ahead Market day in which a different Transaction ID is used.

3.3 Formula for Determining Day-Ahead BPCGs for Imports

Day-Ahead Bid Production Cost Guarantee for Import t by Supplier ~~s~~ =

Section 7 of this Attachment C for a description of the treatment of long start-up Generators that are aborted by the ISO prior to running in real-time.

$$\max\left[\sum_{h=1}^{n}\left(\mathrm{DecBid}_{th}^{DA}-\mathrm{LBMP}_{th}^{DA}\right)*\mathrm{SchImport}_{th}^{DA},0\right]$$

Where;

N = number of hours in the Day-Ahead Market day;

$DecBid_{th}^{DA}$ = Decremental Bid, in $/MWh, supplied ~~by Supplier s~~ for Import t for hour h;

$LBMP_{ph}^{DA}$ = Day-Ahead LBMP, in $/MWh, for hour h at the Proxy Generator Bus ~~p which~~ that is the source of the Import t ~~supplied by Supplier s;~~ and

$SchImport_{th}^{DA}$ = total Day-Ahead schedule, in MWh, for Import t ~~by Supplier s~~ in hour h.

~~.~~ 4.0 ~~B.~~ REAL-TIME BPCG ~~id Production Guarantee Formulas~~ FOR GENERATORS ~~All IMPORTS~~EXCEPT ~~and Real-Time Bid Production Guarantee Formulas~~ FOR ~~All~~ SUPPLEMENTAL EVENT INTERVALS ~~WITH No Maximum Generation Pickups or Large Event Reserve Pickups for All Other Generators~~

4.1 Eligibility for Receiving Real-Time BPCGs for Generators Except for Supplemental Event Intervals

(a) *Eligibility*.

A Supplier shall be eligible to receive a real-time BPCG for ~~all~~ intervals (excluding ~~intervals of Suppliers with~~ Supplemental Event Intervals ~~eligibility in those intervals s as described in Section 5.0 of this Attachment C)~~ and intervals described in Section 4.1(b)(iii) of this Attachment C) if it bids on behalf of:

(i) an ISO-Committed Flexible Generator or an ISO-Committed Fixed Generator that is committed by the ISO in the Real-Time Market;

(ii) a Self-Committed Flexible Generator if the Generator's minimum generation level does not exceed its Day-Ahead schedule at any point during the Dispatch Day, or

(iii) Resources committed via SRE, or committed or dispatched by the ISO as Out-of-Merit Generation to ensure NYCA or local system reliability~~, shall remain eligible to receive a real-time Bid Production Cost guarantee payment~~ for the hours of the day that they are committed via SRE or are committed or dispatched by the ISO as Out-of-Merit Generation to meet NYCA or local reliability without regard to the Bid mode(s) employed during the Dispatch Day~~.~~;

provided, however, that Generators that Bid in Self-Committed mode only (i) during ISO authorized Start-Up, Shutdown or Testing Periods, and (ii) hours when they are committed via SRE or are committed or dispatched by the ISO as Out-of-Merit Generation to meet NYCA or local reliability, will not be precluded from receiving a real-time BPCG~~id Production Cost guarantee payment~~ for the other hours of the Dispatch Day due to these Self-Committed mode Bids.[15]

(b) *Non-Eligibility*.

Notwithstanding Section 4.1(a):

(i) a Supplier that bids on behalf of a Limited Energy Storage Resource shall not be eligible to receive a real-time BPCG;[16]

(ii) a Supplier shall not be eligible to receive a real-time BPCG under this Section 4.0 for an External Transaction; and[17]

(iii) a Supplier that bids on behalf of a Generator ~~during an interval~~ in which the dispatch of the Generator is constrained by its downward ramp rate for that interval, other than a Generator scheduled to provide Regulation Service in that interval with an RTD basepoint less than its AGC basepoint, shall not be eligible to receive a real-time BPCG for that interval.[18]

4.2 Formula for Determining Real-Time BPCGs for Generators Except for Supplemental Event Intervals

Real-Time Bid Production Cost Guarantee for Generator g =[19]

$$\max\left[\left(\sum_{i=1}^{M}\left(\left(\int_{\max(EI_{gi}^{DA},MGI_{gi}^{RT})}^{\max(EI_{gi}^{RT},MGI_{gi}^{RT})} C_{gi}^{RT} + MGC_{gi}^{RT}\cdot\left(MGI_{gi}^{RT}-MGI_{gi}^{DA}\right) - LBMP_{gi}^{RT}\cdot\left(EI_{gi}^{RT}-EI_{gi}^{DA}\right)\right)\cdot\frac{s_i}{3600} - \left(NASR_{gi}^{TOT}-NASR_{gi}^{DA}\right) - RRAP_{gi} + RRAP_{gi}\right) + \sum_{j\in L} SUC_{gj}^{RT}\cdot\left(NSUI_{gj}^{RT}-NSUI_{gj}^{DA}\right)\right),0\right].$$

[15] This sentence was originally located in Section 4.10 of the Services Tariff (Tariff Sheets 106.01 and 106.02).

[16] The substance of this sentence was originally located in Section 4.10 of the Services Tariff (Tariff Sheet 106).

[17] The substance of this sentence was originally located in Section 4.10 of the Services Tariff (Tariff Sheet 106.01).

[18] The substance of this sentence was originally located in Section I.B of Attachment C of the Services Tariff (Tariff Sheet 423).

[19] In the following formula, the symbols "Σ" and "g∈G" have been removed from the start of the equation.

$$\sum_{g\in G}\max\left\{\left[\sum_{i=1}^{N}\left(\left(\int_{EI_{gi}^{DA}}^{EI_{gi}^{RT}} C_{gi}^{RT} + MGC_{gi}^{RT}\left(MGI_{gi}^{RT} - MGI_{gi}^{DA}\right) - LBMP_{gi}^{RT}\left(EI_{gi}^{RT} - EI_{gi}^{DA}\right)\right) * \frac{s_i}{3600} - \left(NASR_{gi}^{TOT} - NASR_{gi}^{DA}\right) - RRAP_{gi} + RRAC_{gi}\right) + \sum_{j=1}^{L} SUC_{gj}^{RT}\left(NSUI_{gj}^{RT} \quad NSUI_{gj}^{DA}\right)\right], 0\right\}$$

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where:

s_i = number of seconds in RTD interval i;

T_{gi}^{RT} = Bilateral Transactions scheduled real-time to be sourced at Generator g in ~~hour h~~ interval i expressed in terms of MW;[20]

T_{gi}^{DA} = Bilateral Transactions scheduled Day-Ahead to be sourced at Generator g in ~~hour h~~ interval i expressed in terms of MW;[21]

C_{gi}^{RT} = Bid cost submitted by Generator g, or when applicable the mitigated Bid cost for Generator g, in the RTD for the hour that includes RTD interval i expressed in terms of \$/MWh, except in hours in which the NYISO has increased Generator g's minimum operating level, either (i) at the Generator's request, or (ii) in order to reconcile the ISO's dispatch with the Generator's actual output or to address reliability concerns that arise because the Generator is not following Base Point Signals, in which case C_{gi}^{RT} shall be deemed to be zero;

MGI_{gi}^{RT} = metered Energy produced by minimum generation segment of Generator g in RTD interval i expressed in terms of MW;

MGI_{gi}^{DA} = Energy scheduled Day-Ahead to be produced by minimum generation segment of Generator g in RTD interval i expressed in terms of MW;

MGC_{gi}^{RT} = Minimum Generation Bid by Generator g, or when applicable the mitigated Minimum Generation Bid for Generator g, in the Real-Time Market for the hour that includes RTD interval i, expressed in terms of \$/MWh;

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[20] The real-time BPCG formula has been modified to account for the effect of Bilateral Transactions on the determination of real-time BPCGs.

[21] The real-time BPCG formula has been modified to account for the effect of Bilateral Transactions on the determination of real-time BPCGs.

SUC_{gj}^{RT} = Start-Up Bid by Generator g, or when applicable the mitigated Start-Up Bid for Generator g, for the hour that includes interval j into RTD expressed in terms of $/start;

provided, however, ~~except~~ that:

(i) the Start-Up Bid ~~SUC_{gi}^{RT}~~ shall be deemed to be zero in the cases of (1~~i~~) Self-Committed Fixed and Self-Committed Flexible Generators, (2~~ii~~) Generators that are economically committed by RTC or RTD that have 10-minute start-up times that are not synchronized and producing Energy within 20 minutes after their scheduled start time, and (3~~iii~~) Generators that are economically committed by RTC that have greater than 10-minute start-up times that are not synchronized and producing Energy within 45 minutes after their scheduled start time;~~.~~ ~~Rules addressing the handling of Start-Up Bids submitted by Generators that are committed via SRE under particular factual circumstances are set forth below;~~[22]

(ii) ~~I~~if a Generator has been committed via SRE and its SRE schedule immediately precedes or follows a real-time commitment that did not result from a Day-Ahead commitment, the Generator's Start-Up Bid included in its daily real-time BPCG~~id Production Cost guarantee~~ calculation for this contiguous real-time commitment period shall be the Start-Up Bid submitted in response to the SRE request (subject to mitigation, where appropriate);

(iii) ~~I~~if a Generator has been committed via SRE and its SRE schedule immediately precedes or follows a real-time schedule that did result~~ed~~ from a Day-Ahead commitment, then the Generator's Start-Up Bid included in its daily real-time BPCG~~id Production Cost guarantee~~ calculation for this contiguous real-time commitment period shall be set to zero~~.~~; and

(iv) if a Generator g has been committed via SRE, the Start-Up Bid by such Generator g, or when applicable the mitigated Start-Up Bid for such Generator g, for the hour that includes interval j shall be reduced pro rata if Generator g fails to complete the lesser of its SRE schedule or its minimum run time;

$NSUI_{gj}^{RT}$ = number of times Generator g started up in the hour that includes RTD interval j;

[22] The rules addressing Start-Up Bids by Generators that are committed via SRE are described in parts (ii), (iii), and (iv) in the definition of the SUC_{gj}^{RT} variable.

$NSUI_{gj}^{DA}$ = number of times Generator g is scheduled Day-Ahead to start up in the hour that includes RTD interval j;

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$LBMP_{gi}^{RT}$ = Real-Time LBMP at Generator g's bus in RTD interval i expressed in terms of \$/MWh;

~~N~~ M = ~~except for imports,~~ the set of ~~number~~ of eligible RTD intervals in the Dispatch Day consisting of all of the RTD intervals in the Dispatch D~~d~~ay except:

(i) ~~excluding~~ Supplemental Event ~~i~~Intervals ~~in which there are any maximum generation pickups or large event reserve pickups and the three RTD intervals following the termination of the large event reserve pickup or maximum generation pickup~~ (which are addressed separately in Section 5.0 ~~subsection I.3~~ below); ~~and~~

(ii) ~~excluding~~ ~~any RTD~~ intervals where EI_{gi}^{RT} is less than or equal to EI_{gi}^{DA}; ~~*provided, however,*~~ and

(iii) ~~excluding~~ intervals during authorized Start-Up Periods, Shutdown Periods, or Testing Periods for Generator g;[23]

~~for imports, the variable N is the number of eligible RTD intervals in the day excluding any RTD intervals where EI_{gi}^{RT} is less than or equal to EI_{gi}^{DA};~~

~~L = all intervals in the Dispatch Dday~~

EI_{gi}^{RT} = either, as the case may be:[24]

(i) if $EOP_{ig} > AEI_{ig}$, then $\min(\max(AEI_{ig}, RTSen_{ig}), EOP_{ig})$; or

(ii) if otherwise, then ~~and~~ $\max(\min(AEI_{ig}, RTSen_{ig}), EOP_{ig})$; ~~otherwise~~

EI_{gi}^{DA} = Energy scheduled in the Day-Ahead Market to be produced by Generator g in the hour that includes RTD interval i expressed in terms of MW, plus the greater of (a) T_{gi}^{RT} minus T_{gi}^{DA} and (b) zero.[25]

$RTSen_{ig}$ = Real-time Energy scheduled for Generator g in interval i, and calculated as

[23] The substance of this part (iii) was originally located on Tariff Sheet 106.02 of Attachment C of the ISO Services Tariff.
[24] The variable EI_{gi}^{RT} was modified to improve its clarity, but was not substantively changed.
[25] The EI_{gi}^{DA} variable has been modified to account for the effect of Bilateral Transactions.

the arithmetic average of the 6-second AGC Base Point Signals sent to Generator g during the course of interval i expressed in terms of MW;

AEI_{ig} = average Actual Energy Injection by Generator g in interval i but not more than $RTSen_{ig}$ plus any Compensable Overgeneration expressed in terms of MW;

EOP_{ig} = the Economic Operating Point of Generator g in interval i expressed in terms of MW;

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$NASR_{gi}^{TOT}$ = Net Ancillary Services ~~scheduled~~ revenue, expressed in terms of $, paid to Generator g as a result of either having been committed Day-Ahead to operate in the hour that includes RTD interval i or having operated in interval i which is computed by summing the following: (1) Voltage Support Service payments received by that Generator for that RTD interval, if it is not a Supplier of Installed Capacity; (2) Regulation Service payments that would be made to that Generator for that hour based on a Performance Index of 1, less the Bid(s) placed by that Generator to provide Regulation Service in that hour at the time it was committed to produce Energy for the LBMP Market and/or Ancillary Services to do so (unless the Bid(s) exceeds the payments that Generator receives for providing Regulation Service, in which case this component shall be zero); (3) payments made to that Generator for providing Spinning Reserve or synchronized 30-Minute Reserve in that hour, less the Bid placed by that Generator to provide such reserves in that hour at the time it was scheduled to do so; and (4) Lost Opportunity Cost payments made to that Generator in that hour as a result of reducing that Generator's output in order for it to provide Voltage Support Service.

$NASR_{gi}^{DA}$ = The proportion of the Day-Ahead net Ancillary Services revenue, expressed in terms of $, that is applicable to interval i calculated by multiplying the $NASR_{gh}^{DA}$ for the hour that includes interval i by $_{Si}$/3600.

$RRAP_{gi}$ = Regulation Revenue Adjustment Payment for Generator g in RTD interval i expressed in terms of $.

$RRAC_{gi}$ = Regulation Revenue Adjustment Charge for Generator g in RTD interval i expressed in terms of $.

~~Time periods including reserve pickups, and time periods following a reserve pickup in which the dispatch of a given Generator is constrained by its downward ramp rate, will not be included in the above calculation of supplemental payments for that Generator.~~

4.3 Bids Used For Intervals at the End of the Hour, ~~the Bid for the Next Hour Shall Apply~~

For RTD intervals in an hour that start 55 minutes or later after the start of that hour, a Bid used to determine real-time BPCGs in Section 4.2 will be the Bid for the next hour in accordance with ISO Procedures. For RTD-CAM intervals in an hour that start 50 minutes or later after the start of that hour, a Bid used to determine real-time BPCGs in Section 4.2 will be the Bid for the next hour, in accordance with ISO Procedures.

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~~Supplemental payments to Generators that trip before completing their minimum run-time (for Generators that were not scheduled to run Day-Ahead) or before running for the number of hours they were scheduled to operate (for Generators scheduled to run Day-Ahead) may be reduced by the ISO, per ISO Procedures.~~[26]

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In the event that the ISO re-institutes penalties for poor Regulation Service performance under Section 8.0 of Rate Schedule 3 such penalties will not be taken into account when calculating supplemental payments under this Attachment C.

5.0 ~~C. Real-Time~~ BPCG~~id Production Cost Guarantees~~ FOR GENERATORS' SUPPLEMENTAL EVENT INTERVALS ~~WITH Maximum Generation Pickups or Large Event Reserve Pickups~~

5.1 Eligibility for BPCGs for Generators' ~~for~~ Supplemental Event Intervals

(a) *Eligibility*.

(i) Any Supplier who meets the eligibility requirements for a real-time BPCG described in Section 4.1(a) of this Attachment C and whose Energy dispatch is the result of a large event reserve pick-up, as described in Section 4.4.4.A.1 of this ISO Services Tariff, shall be eligible to receive a BPCG under this Section 5.0.[27]

(ii) Any Supplier whose Generator is located in the location(s) for which an emergency has been declared under Section 4.4.4.A.2 of this ISO Services Tariff and is requested to dispatch Energy as the result of a maximum generation pick-up shall be eligible to receive a BPCG under this Section 5.0.

(b) *Non-Eligibility*.

Notwithstanding Section 5.1(a), a Supplier shall not be eligible to receive a BPCG for Supplemental Event Intervals if the Supplier is not eligible for a real-time BPCG for the reasons described in Section 4.1(b) of this Attachment C provided however, a Supplier that bids on

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[26] The substance of this sentence has been relocated to the variable "SUC_{gh}^{DA}" in Section 2.2 of this Attachment C and to the variable "SUC_{gi}^{RT}" in Section 4.2 of this Attachment C.

[27] The NYISO is proposing a change to ensure that these BPCGs only apply to Suppliers whose dispatch is affected, and not to all Suppliers. A code change is required to ensure that these BPCGs only apply to Suppliers whose dispatch is affected by a large event reserve pick-up and not to all Suppliers. The code change is currently expected to be completed at the same time that the revised tariff sheets become effective.

behalf of a Generator in which the dispatch of the Generator is constrained by its downward ramp rate for that interval shall be eligible for Generator Supplemental Event Interval BPCGs .

5.2 Formula for Determining BPCGs for Generators for Supplemental Event Intervals

Real-Time Bid Production Cost Guarantee Payment for Generator g =

$$\max\left(\sum_{i=1}^{P}\left(\left(\int_{\max\left(EI_{gi}^{DA},MGI_{gi}^{RT}\right)}^{\max\left(EI_{gi}^{RT},MGI_{gi}^{RT}\right)} C_{gi}^{RT} + MGC_{gi}^{RT}\cdot\left(MGI_{gi}^{RT}-MGI_{gi}^{DA}\right) - LBMP_{gi}^{RT}\cdot\left(EI_{gi}^{RT}-EI_{gi}^{DA}\right)\right)\cdot\frac{s_i}{3600} - \left(NASR_{gi}^{TOT}-NASR_{gi}^{DA}\right) - RRAP_{gi} + RRAP_{gi}\right),0\right)$$

$$\sum_{g\in G}\left[\sum_{i=1}^{M}\max\left(\left(\int_{EI_{gi}^{DA}}^{EI_{gi}^{RT}} C_{gi}^{RT} + MGC_{gi}^{RT}\left(MGI_{gi}^{RT}-MGI_{gi}^{DA}\right) - LBMP_{gi}^{RT}\left(EI_{gi}^{RT}-EI_{gi}^{DA}\right)\right)*\frac{s_i}{3600} - \left(NASR_{gi}^{TOT}-NASR_{gi}^{DA}\right) - RRAP_{gi} + RRAC_{gi},0\right)\right]$$

where:

P = ~~number~~ the set of Supplemental Event ~~i~~Intervals~~ in which there are maximum generation pickups or large event reserve pickups in the 24 -hour day and the three RTD intervals following the termination of the large event reserve pickup or maximum generation pickup,~~[28] in the Dispatch Day but excluding any intervals in which there are maximum generation pickups or large event reserve pickups where EI_{gi}^{RT} is less than or equal to EI_{gi}^{DA}; and

EI_{gi}^{RT} = (i) for any intervals in which there are maximum generation pickups, and the three intervals following, the average Actual Energy Injections, expressed in MWh, for Generator g in interval i, and

(ii) for any intervals in which there are large event reserve pickups and the three intervals following, EI_{gi}^{RT} is as defined in Section 4.2 above.[29]

[28] The deleted language is included in the definition of the term "Supplemental Event Intervals."
[29] The current formula for real-time BPCGs for Generators for Supplemental Event Intervals does not account for the difference in the determination of Energy injections for the calculation of BPCGs for intervals in which there are

The definition of all other variables is identical to those defined in Section 4.2~~I.B~~ above.

In the event that the ISO re-institutes penalties for poor Regulation Service performance under Section 8.0 of Rate Schedule 3 such penalties will not be taken into account when calculating supplemental payments under this Attachment C.

6.0 REAL-TIME BPCGS FOR IMPORTS

6.1 Eligibility for Receiving Real-Time BPCGs for Imports

(a) *Eligibility.*

A Supplier that bids an Import that is committed by the ISO in the Real-Time Market shall be eligible to receive a real-time BPCG for all intervals.

(b) *Non-Eligibility.*

Notwithstanding Section 6.1(a):

(i) ~~W~~when a Non-Competitive Proxy Generator Bus or the Interface between the NYCA and the Control Area in which the Non-Competitive Proxy Generator Bus is located is export constrained due to limits on ~~A~~available Interface Capacity or Ramp Capacity limits for that Interface in an hour, External Generators and other Suppliers scheduling an Import~~s~~ at such Non-Competitive Proxy Generator Bus in that hour ~~wi~~shall not be eligible for a r~~R~~eal-t~~T~~ime BPCG ~~shortfall payments~~ for thi~~s~~~~ose~~ Transaction~~s.~~; and

(ii) ~~W~~when a Proxy Generator Bus that is associated with a designated Scheduled Line is export constrained due to limits on ~~A~~available Interface Capacity in an hour, External Generators and other Suppliers scheduling an Import~~s~~ at such Proxy Generator Bus in that hour will not be eligible for a real-time BPCG ~~shortfall payments~~ for thi~~o~~se Transaction~~s~~.

6.2 BPCGs Calculated by Transaction ID

For purposes of calculating a real-time BPCG for an Import under this Section 6.0, the ISO shall treat the Import as being from a single Resource for all hours of the Dispatch Day in which the same Transaction ID is used, and the ISO shall treat the Import as being from a different Resource for all hours of the Dispatch Day in which a different Transaction ID is used.

6.3 Formula for Determining Real-Time BPCGs for Imports

maximum generation pickups and for intervals in which there are large event reserve pickups. This modification clarifies this distinction.

Real-Time Bid Production Cost Guarantee for Import t by Supplier s =

$$Max\left(\sum_{i=1}^{Q}\left[\left(\mathrm{DecBid}_{ti}^{RT}-\mathrm{LBMP}_{ti}^{RT}\right)*\max\left(\mathrm{SchImport}_{ti}^{RT}-\mathrm{SchImport}_{ti}^{DA},0\right)*S_i/3600\right],0\right)$$

Where:

Q = number of intervals in the Dispatch Day;

$DecBid_{ti}^{RT}$ = Decremental Bid, in $/MWh, supplied ~~by Supplier s~~ for Import t for interval i;

$LBMP_{pi}^{RT}$ = real-time LBMP, in $/MWh, for interval i at Proxy Generator Bus ~~p~~ which is the source of the Import t ~~supplied by Supplier s~~;

$SchImport_{ti}^{RT}$ = total real-time schedule, in MW, for Import t ~~by Supplier s~~ in interval i; and

$SchImport_{ti}^{DA}$ = total Day-Ahead schedule, in MW, for Import t ~~by Supplier s~~ in hour that contains interval i.

S_i, = number of seconds in RTD interval i.

7.0 BPCGS FOR LONG START-UP TIME GENERATORS THAT ARE ABORTED BY THE ISO PRIOR TO THEIR DISPATCH

7.1 Eligibility for BPCGs for Long Start-Up Time Generators that Are Aborted by the ISO Prior to their Dispatch

A Supplier that bids on behalf of a long start-up time Generator (i.e., a Generator that cannot be scheduled by SCUC to start up in time for the next Dispatch Day) that is committed by the ISO for reliability purposes as a result of a Supplemental Resource Evaluation and is aborted by the ISO prior to its dispatch, as described in Section 4.2.5 of the ISO Services Tariff, shall be eligible to receive a BPCG under this Section 7.0.

7.2 Methodology for Determining BPCGs for Long Start-Up Time Generators that Are Aborted by the ISO Prior to their Dispatch

A Supplier~~Generators~~ whose~~ith~~ long start-up time~~s~~ Generator's start-up is aborted shall receive ~~of greater than twenty-four (24) hours will have their start-up cost Bids equally~~ a prorated portion of its Start-Up Bid for the hour in which the ISO requested that the Generator begin its start-up sequence,~~over the course of each day included in their start-up period.~~

~~Consequently, units whose start-ups are aborted will receive a prorated portion of those payments,~~ based on the portion of the start-up sequence that it~~ey~~ has~~ve~~ completed (*e.g.*, if a long start-up time Generator ~~unit~~ with a seventy-two (72) hour start-up time has its start-up sequence aborted after forty-eight (48) hours, it would receive two-thirds (2/3) of its ~~s~~Start-~~u~~Up ~~cost~~ Bid).

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~~II.~~8.0 ~~Supplemental Payments FOR CURTAILMENT INITIATION COSTS~~BPCG FOR DEMAND REDUCTION IN THE DAY-AHEAD MARKET

8.1 Eligibility for BPCG for Demand Reduction in the Day-Ahead Market

A Demand Reduction Provider that bids a Demand Side Resource that is committed by the ISO in the Day-Ahead Market to provide Demand Reduction shall be eligible to receive a BPCG under this Section 8.0.

8.2 Formula for Determining BPCGs for Demand Reduction in the Day-Ahead Market

~~A supplemental payment for Curtailment Initiation Costs shall be made when the Curtailment Initiation Cost Bid and the Demand Reduction Bid price offered by a Demand Reduction Provider for any Demand Reduction committed by the ISO in the Day-Ahead market over the [twenty-four (24) hour] day exceeds Day-Ahead LBMP revenue, *provided however* that~~

~~Supplemental payments made to Demand Reduction Providers that fail to complete their scheduled reductions may be reduced by the ISO, pursuant to ISO Procedures.~~[30]

Day-Ahead BPCG for Demand Reduction Provider d =

$$\text{Max}\left[\sum_{h=1}^{N}\left(\text{MinCurCost}_d^h + \text{IncrCurCost}_d^h - \text{CurRev}_d^h\right) + \text{CurInitCost}_d, 0\right]$$

where:

$$\text{CurInitCost}_d = \left(\sum_{h=1}^{N}\left(Min\left(\text{ActCur}_d^h, \text{SchdCur}_d^h\right)\right) / \left(\sum_{h=1}^{N}\text{SchdCur}_d^h\right)\right) * \text{CurCost}_d$$

$$\text{MinCurCost}_d^h = \text{Min}\left[\left(\max\left(\text{ActCur}_d^h, 0\right), \text{MinCur}_d^h\right)\right] * \text{MinCurBid}_d^h$$

[30] The formula in Section 8.2 of this Attachment C addresses the reduction of BPCGs for Demand Reduction Providers that fail to complete their scheduled reductions.

$$\text{IncrCurCost}_d^h = \int_{\text{MinCur}_d^h}^{\max(\text{MinCur}_d^h,\min(SchdCur_d^h,ActCur_d^h))} \text{IncrCurBid}_d^h]$$

$$\text{CurRev}_d^h = \text{LBMP}_{dh}^{DA} * \min(\max(\text{ActCur}_d^h, 0), \text{SchdCur}_d^h)$$

N = number of hours in the Day-Ahead Market day.

$CurInitCost_d$ = daily Curtailment Initiation Cost credit for Day-Ahead Demand Reduction Provider d;

$MinCurCost_d^h$ = minimum Curtailment cost credit for Day-Ahead Demand Reduction Provider d in hour h;

$IncrCurCost_d^h$ = incremental Curtailment cost credit for Day-Ahead Demand Reduction Provider d for hour h;

$CurCost_d$ = total bid Curtailment Initiation Costs for Day-Ahead Demand Reduction Provider d for the day;

$CurRev_d^h$ = actual revenue for Day-Ahead Demand Reduction Provider d in hour h;

$ActCur_d^h$ = actual Energy curtailed by Day-Ahead Demand Reduction Provider d in hour h expressed in terms of MWh;

$SchdCur_d^h$ = Energy scheduled Day-Ahead to be curtailed by Day-Ahead Demand Reduction Provider d in hour h expressed in terms of MWh;

$MinCurBid_d^h$ = minimum Curtailment initiation Bid submitted by Day-Ahead Demand Reduction Provider d for hour h expressed in terms of \$/MWh;

$IncrCurBid_d^h$ = Bid cost submitted by Day-Ahead Demand Reduction Provider d for hour h expressed in terms of \$/MWh;

$MinCur_d^h$ = Energy scheduled Day-Ahead to be produced by the minimum Curtailment segment of Day-Ahead Demand Reduction Provider d for hour h expressed in terms of MWh; and

$LBMP_{dh}^{DA}$ = Day-Ahead LBMP for Day-Ahead Demand Reduction Provider d for hour h expressed in \$/MWh.

~~III~~9.0 ~~SUPPLEMENTAL PAYMENTS~~ BPCG FOR SPECIAL CASE RESOURCES

9.1 Eligibility for Special Case Resources BPCGs

Any Supplier that bids a Special Case Resource that is committed by the ISO in the Real-Time Market shall be eligible to receive a BPCG under this Section 9.0.

9.2 Methodology for Determining Special Case Resources BPCGs

A Special Case Resource BPCG~~supplemental payment~~ ~~for Minimum Payment Nominations~~ shall be made when the Minimum Payment Nomination for any Special Case Resource committed by the ISO over the period of requested performance or four (4) hours, whichever is greater,[31] exceeds the LBMP revenue received for performance by that Special Case Resource; *provided, however*, that the ISO shall set to zero the Minimum Payment Nomination for Special Case Resource Capacity in each interval in which such capacity was scheduled Day-Ahead to provide Operating Reserves, Regulation Service or Energy.

~~IV~~10.0 ~~SUPPLEMENTAL PAYMENTS~~BPCG FOR DEMAND SIDE RESOURCES PROVIDING SYNCHRONIZED~~Synchronized~~ OPERATING RESERVES ~~AND REGULATION SERVICE~~ IN THE DAY-AHEAD MARKET

10.1 Eligibility for BPCGs for Demand Side Resources Providing Synchronized Operating Reserves ~~and Regulation Service~~ in the Day-Ahead Market

Any Supplier that bids a Demand Side Resource that is committed by the ISO to provide synchronized Operating Reserves ~~and Regulation Service~~ in the Day-Ahead Market shall be eligible to receive a BPCG under this Section 10.0.

10.2 Formula for Determining BPCGs for Demand Side Resources Providing Synchronized Operating Reserves ~~and Regulation Service~~ in the Day-Ahead Market

~~A.~~ A BPCG~~supplemental payment~~ to a Demand Side Resource with a synchronized Operating Reserves ~~or Regulation Service~~ schedule in the Day-Ahead Market shall be calculated as follows: ~~by setting to zero all terms provided in Section I. A. of this Attachment C, with which Day-Ahead supplemental payments are calculated, with the exception of the term $NASR_{gh}^{DA}$ which shall be calculated pursuant to its description.~~[32]

BPCG for Demand Side Resource d Providing ~~Ancillary Services~~ synchronized Operating Reserves Day-Ahead =

$$\max\left[\left(-\sum_{h=1}^{N} NASR_{dh}^{DA}\right),0\right]$$

[31] The substance of this provision was originally located in Section 4.10 of the ISO Services Tariff (Tariff Sheets 106A and 140A).

[32] The formula for determining BPCGs for Demand Side Resources providing synchronized Operating Reserves in the Day-Ahead Market that was originally included in this section only functioned for Generators. A new formula has been included that functions for Demand Side Resources. This formula is substantively unchanged, but the variables are appropriate for Demand Side Resources, rather than Generators.

where:

N = number of hours in the Day-Ahead Market day.

$NASR_{dh}^{DA}$ = Net Ancillary Services revenue, in \$, paid to Demand Side Resource d as a result of having been committed to provide Ancillary Services Day-Ahead ~~to operate~~ in hour h which is computed by summing the following: (1) Regulation Service payments made to that Demand Side Resource for all Regulation Service it is scheduled Day-Ahead to provide in that hour, less Demand Side Resource d's Day-Ahead Bid to provide that amount of Regulation Service in that hour (unless the Bid exceeds the payments that the Demand Side Resource receives for providing Regulation Service that was committed to provide Ancillary Services Day-Ahead, in which case this component shall be zero); and (2) payments made to Demand Side Resource d for providing Spinning Reserve and synchronized 30-Minute Reserve in that hour if it is committed Day-Ahead to provide such reserves in that hour, less Demand Side Resource d's Day-Ahead Bid to provide Spinning Reserve and synchronized 30-Minute Reserve in that hour.

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11.0 BPCG FOR DEMAND SIDE RESOURCES PROVIDING SYNCHRONIZED OPERATING RESERVES ~~AND REGULATION SERVICE~~ IN THE REAL-TIME MARKET

11.1 Eligibility for BPCGs for Demand Side Resources Providing Synchronized Operating Reserves ~~and Regulation Service~~ in the Real-Time Market

Any Supplier that bids a Demand Side Resource that is committed by the ISO to provide synchronized Operating Reserves ~~and Regulation Service~~ in the Real-Time Market shall be eligible to receive a BPCG under this Section 11.0.

11.2 Formula for Determining BPCGs for Demand Side Resources Providing Synchronized Operating Reserves ~~and Regulation Service~~ in the Real-Time Market

~~B.~~ A BPCG ~~supplemental payment~~ to a Demand Side Resource with a synchronized Operating Reserves schedule in the real-time Market shall be calculated as follows: ~~by setting to zero all terms provided in Section I.B. of this Attachment C, with which real-time supplemental payments are calculated, with the exception of the terms~~ ~~$NASR_{gi}^{DA}$~~ ~~and~~ ~~$NASR_{gi}^{TOT}$~~~~, which shall be calculated pursuant to their description.~~[33]

[33] The formula for determining BPCGs for Demand Side Resources providing synchronized Operating Reserves and Regulation Services in the Real-Time Market that was originally included in this section only functioned for

BPCG for Demand Side Resource d Providing ~~Ancillary Services~~ synchronized Operating Reserves in Real-Time =

$$\max\left[-\sum_{i=1}^{N}\left\langle NASR_{di}^{TOT}-NASR_{di}^{DA}\right\rangle,0\right]$$

where:

N = number of hours in the Dispatch Day;

$NASR_{di}^{TOT}$ = Net Ancillary Services ~~scheduled~~ revenue, in $, paid to Demand Side Resource d as a result of either having been scheduled Day-Ahead in the hour that includes RTD interval i or having been scheduled in real-time in interval i is computed by summing the following: (1) Regulation Service payments that would be made to Demand Side Resource d for that hour based on a Performance Index of 1, less the Bid(s) placed by Demand Side Resource d to provide Regulation Service in that hour at the time it was committed to provide Ancillary Services (unless the Bid(s) exceeds the payments that Demand Side Resource d receives for providing Regulation Service, in which case this component shall be zero); (2) payments made to Demand Side Resource d for providing Spinning Reserve or synchronized 30-Minute Reserve in that hour, less the Bid placed by Demand Side Resource d to provide such reserves in that hour at the time it was scheduled to do so; and

$NASR_{di}^{DA}$ = The proportion of the Day-Ahead net Ancillary Services revenue, in $, that is applicable to interval i calculated by multiplying the $NASR_{dh}^{DA}$ for the hour that includes interval i by the quotient of the number of seconds in RTD interval i divided by 3600.

Generators. A new formula has been included that functions for Demand Side Resources. The formula is substantively unchanged, but the variables are appropriate for Demand Side Resources, rather than Generators.

Attachment J (Services Tariff)

Sixth Revised Sheet No. 486

ATTACHMENT J
DETERMINATION OF DAY-AHEAD MARGIN ASSURANCE PAYMENTS

AND IMPORT CURTAILMENT GUARANTEE PAYMENTS

1.0 Introduction~~General Rule~~

If a~~n~~ ~~eligible~~ Supplier that is eligible pursuant to Section 2.0 of this Attachment J buys out of a Day-Ahead Energy, Regulation Service or Operating Reserve schedule in a manner that reduces its Day-Ahead Margin it shall receive a Day-Ahead Margin Assurance Payment, except as noted in Sections 4.0~~,~~ and 5.0 of this Attachment J. The purpose of such payments is to protect Suppliers' Day-Ahead Margins associated with real-time reductions after accounting for: (i) any real-time profits associated with offsetting increases in real-time Energy, Regulation Service, or Operating Reserve s~~S~~chedules; and (ii) any Supplier-requested real-time de-rate granted by the ISO. ~~Day-Ahead Margin Assurance Payments payable to Limited Energy Storage Resources~~

In addition, a Supplier may be eligible to receive an Import Curtailment Guarantee Payment if its Import is curtailed at the request of the ISO as ~~shall be~~ determined pursuant to Section 6.0 of this Attachment J.

2.0 Eligibility for Receiving Day-Ahead Margin Assurance Payments

2.1 General Eligibility Requirements for Suppliers to Receive Day-Ahead Margin Assurance Payments

Subject to Section 2.2 of this Attachment J, ~~T~~the following categories of Suppliers shall be eligible to receive Day-Ahead Margin Assurance Payments ~~provided however, that intermittent Power Resources depending on wind as their fuel shall not be eligible for Day-Ahead Margin Assurance Payments~~: (i) all Self-Committed Flexible and ISO-Committed Flexible Generators that are online and dispatched by RTD; (ii) Demand Side Resources committed to provide Operating Reserves or Regulation Service; (iii) any Supplier that is scheduled out of economic merit order by the ISO in response to an ISO or Transmission Owner system security need or to permit the ISO to procure additional Operating Reserves; (iv) any Supplier internal to the NYCA that is derated or

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decommitted by the ISO in response to an ISO or Transmission Owner system security need or to permit the ISO to procure additional Operating Reserves; and (v) Energy Limited Resources with a ~~total~~ margin ~~for the dispatch day that is less than its Day-Ahead margin as a result of~~ an ISO-approved real-time reduction in scheduled output from its Day-Ahead schedule ~~for Energy limited reasons~~.

2.2 Exceptions

Notwithstanding Section 2.1 of this Attachment J, ~~N~~no Day-Ahead Margin Assurance Payment shall be paid to

(i) a Supplier~~Generator,~~ otherwise eligible for a Day-Ahead Margin Assurance Payment~~,~~ in hours in which the NYISO has increased the Supplier's ~~Generator's~~ minimum operating level~~,~~ either: (a~~i~~) at the Generator's request; or (b~~ii~~) in order to reconcile the ISO's dispatch with the Generator's actual output or to address reliability concerns that arise because the Generator is not following Base Point Signals; or

(ii) ~~.~~ an Intermittent Power Resource that depends on wind as its fuel.

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3.0 Calculation of Day-Ahead Margin Assurance Payments

3.~~0.~~1 Formula for Day-Ahead Margin Assurance Payments for Generators, Except for Limited Energy Storage Resources

Subject to Sections 4.0 and 5.0 of this Attachment J, Day-Ahead Margin Assurance Payments for Generators, except for Limited Energy Storage Resources, shall be determined by applying the following equations to each individual Generator using the terms as defined in ~~subs~~Section 3.4~~03~~:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

3.~~0~~2. Formula for Day-Ahead Margin Assurance Payments for Demand Side Resources

A. Formula for Day-Ahead Margin Assurance Payment for Demand Side Resources

Subject to Section 5.0 of this Attachment J, Day-Ahead Margin Assurance Payments for Demand Side R~~r~~esources scheduled to provide Operating Reserves or Regulation Service shall be determined by applying the following equations to each individual Demand Side Resource using the terms as defined in ~~subs~~Section 3.4, except for RPIiu, which is defined in Section 3.2.B.~~03~~:

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

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

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

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

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

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

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

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

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

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

B. Reserve Performance Index for Demand Side Resource Suppliers of Operating Reserves

The ISO shall produce a Reserve ~~p~~Performance ~~i~~Index for purposes of calculating a Day Ahead Margin Assurance ~~p~~Payment for a Demand Side Resource providing Operating Reserves. The Reserve ~~p~~Performance ~~i~~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 Reserve ~~p~~Performance ~~i~~Index shall be a factor with a value between 0.0 and 1.0 inclusive. For each interval in which the ISO has not instructed the Demand Side Resource to covert its Operating Reserves to Demand Reduction, the Reserve 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 Reserve 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:

$$R\cancel{eserve}\ PI_{iu} = \text{Min}\left[(UAGi / ADGi + .1), 1\right]$$

Where:

R~~eserve~~ PI_{iu} = Reserve Performance Index in interval i for Demand Side Resource u;

UAGi = ~~A~~average actual ~~d~~Demand ~~r~~Reduction for interval i, represented as a positive generation value; and

ADGi = ~~A~~average scheduled ~~d~~Demand ~~r~~Reduction for interval i, represented as a positive generation base point.

3.3 Formula for Day-Ahead Margin Assurance Payments for Limited Energy Storage Resources

~~A.~~ Day-Ahead Margin Assurance Payments for Limited Energy Storage Resources scheduled to provide Regulation Service shall be determined by applying the following equations to each Resource using the terms as defined in ~~subs~~Section 3.~~4~~03~~,~~; *provided*, *however*, that a Day-Ahead Margin Assurance Payment is payable only for intervals in which the NYISO has reduced the real-time Regulation Service offer (in MWs) of a Limited Energy Storage Resource ~~to account for the Energy storage capacity of such Resource~~ and the NYISO is not pursuing LESR Energy Management for such Resource for such interval, pursuant to ISO Procedures:

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

$$CDMAPreg_{iu} = [(DASre_{hu} - RTSreg_{iu}) * (RTPreg_{iu} - DABreg_{h})] * K_{PI} * \frac{Seconds_i}{3600}$$

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

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

3.4~~03~~ Terms U~~u~~sed in~~s~~ this Attachment J~~:~~

The terms used in the formulas in this Attachment J shall be defined as follows:

h is the hour that includes interval *i*;

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

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

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

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

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

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

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

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

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

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

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

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

$RTSreg_{iu}$ = r~~R~~eal-time schedule for Regulation Service for Supplier *u* in interval *i*.

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

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

$RTBen_{iu}$ = r~~R~~eal-time Energy bid curve for Supplier *u* in interval *i*.

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

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

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

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

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LL_{iu} = either, as the case may be:

(a) if $RTSen_{iu} < EOP_{iu}$, then $LL_{iu} = \min(\max(RTSen_{iu}, \min(AEI_{iu},EOP_{iu})), DASen_{hu})$; or

(b) if $RTSen_{iu} \geq EOP_{iu}$, then LL_{iu} = ~~min(~~$\min(RTSen_{iu}, \max(AEI_{iu},EOP_{iu}), DASen_{hu})$~~), $DASen_{hu}$);~~[34]

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

UL_{iu} = either, as the case may be:

(a) if $RTSen_{iu} \geq EOP_{iu} \geq DASen_{hu}$, then $UL_{iu} = \max(\min(RTSen_{iu}, \max(AEI_{iu},EOP_{iu})), DASen_{hu})$; or

[34] The modifications to the definition of the variable LL_{iu} were made to improve the readability of the definition and do not change the substance of the definition.

(b) otherwise, then UL_{iu} = ~~max (~~max ($RTSen_{iu}$, min(AEI_{iu},EOP_{iu})~~)~~, $DASen_{hu}$);[35] ~~min ($RTSen_{iu}$, max(AEI_{iu},EOP_{iu})) but not less than $DASen_{hu}$ if $RTSen_{iu} \geq EOP_{iu} \geq DASen_{hu}$ and max ($RTSen_{iu}$, min(AEI_{iu},EOP_{iu})) but not less than $DASen_{hu}$ otherwise;~~

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

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

~~RPIiu = the Reserves Performance Index in interval i for Demand Side Resource u. The Reserves Performance Index is calculated pursuant to Section 3.6 of Rate Schedule 4 of this Services Tariff.~~[36]

K_{PI} = the factor derived from the Regulation Service Performance index for Resource u for interval i as defined in Rate Schedule 3 of this Services Tariff which shall initially be set at 1.0 for LESRs.

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~~**3.04** Other Provisions~~

~~The AGC Base Point Signal for a Supplier that is not providing Regulation Service during a given RTD interval shall be initialized by either: (i) the Supplier's last AGC Base Point Signal from the prior RTD interval; or (ii) the Supplier's actual metered generation or calculated Demand Reduction at the time new RTD Base Point Signals are received by the ISO's AGC software, whichever is closer to the Supplier's new RTD Base Point Signal. AGC Base Point Signals for a Supplier that is not providing Regulation Service will ramp evenly over the course of the RTD interval starting at the initialized AGC Base Point Signal and ending at the level of its new RTD Base Point Signal. AGC Base Point Signals for Suppliers providing Regulation Service during a given RTD interval are determined based on the ISO's need to minimize the NYCA area control error.~~[37]

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4.0 Exception for Generators Lagging Behind RTD Base Point Signals

[35] The modifications to the definition of the variable UL_{iu} were made to improve the readability of the definition and do not change the substance of the definition.

[36] This provision is addressed in Section 3.2.B of this Attachment J.

[37] This provision contains historic language that no longer serves any purpose in Attachment J. For this reason, the NYISO is deleting this language.

~~An otherwise eligible Generator that does not respond to, or that lags behind, the ISO's RTD Base Point Signals in a given interval, as determined below, shall not be eligible for Day-Ahead Margin Assurance Payments for that interval.~~ [38]If an otherwise eligible~~such a~~ Generator's average Actual Energy Injection in an RTD interval (*i.e.*, its Actual Energy Injections averaged over the RTD interval) is less than or equal to its penalty limit for under-generation value for that interval, as computed below, it shall not be eligible for Day-Ahead Margin Assurance Payments for that interval.

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

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5.0 Rules Applicable to Supplier Derates

Suppliers that request and are granted a derate of their real-time Operating Capacity, but that are otherwise eligible to receive Day-Ahead Margin Assurance Payments may receive a payment up to a Capacity level consistent with their revised Emergency Upper Operating Limit or Normal Upper Operating Limit, whichever is applicable. The foregoing rule shall also apply to a Generator~~,~~ otherwise eligible for a Day-Ahead Margin Assurance Payment~~,~~ in hours in which the ISO has derated the Generator's Operating Capacity in order to reconcile the ISO's dispatch with the Generator's actual output, or to address reliability concerns that arise because the Generator is not following Base Point Signals. If a Supplier's

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derated real-time Operating Capacity is lower than the sum of its Day-Ahead Energy Regulation Services and Operating Reserve schedules then when the ISO conducts the calculations described in Section 3.0 above, the DASen, DASeg and $DASres_p$ variables will be reduced by REDen, REDreg and $REDres_p$ respectively. REDen, REDreg and $REDres_p$ shall be calculated using the formulas below:

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

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

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

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

[38] Section 4.0 creates an exception to make Generators that lag behind their Base Point Signals ineligible for a DAMAP. The first sentence states the rule in a simplified fashion, but the second sentence does so specifically. The contradiction was not intended and has been addressed by deleting the first sentence.

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

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

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

where:

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

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

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

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

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

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

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

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

All other variables are as defined above.

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6.0 IMPORT CURTAILMENT GUARANTEE PAYMENTS

6.1 Eligibility for an Import Curtailment Guarantee Payment for an Import Curtailed by the ISO

In the event that the Energy injections scheduled by RTC_{15} at a Proxy Generator Bus are Curtailed at the request of the ISO, then the Supplier or Transmission Customer that is subjected to the Curtailment, in addition to the charge for Energy Imbalance, shall be eligible for an Import Curtailment Guarantee Payment as determined in Section 6.2 of this Attachment J.

6.2 Formula for an Import Curtailment Guarantee Payment for a Supplier Whose Import Was Curtailed by the ISO

A Supplier eligible under Section 6.1 of this Attachment J shall receive an Import Curtailment Guarantee Payment for its curtailed ~~Energy injections~~Energy injections that is equal to the sum for each hour of the interval payments determined in the formula below.

Import Curtailment Guarantee Payment to Supplier u =

$$\mathrm{Max}\{(RTLBMP_{p,i} - \max(DecBid_{t,i}, 0))\ ((RTCen_{t,i} - RTDen_{t,i})\ S_i/3600),0\}$$

$$\cancel{\max\left(\left(RTLBMP_{p,i} - \max\left(DecBid_{u,i},0\right)\right)\left(\left(RTCen_{u,i} - RTDen_{u,i}\right)\frac{S_i}{3600}\right),0\right)}$$

Where

~~u = Supplier;~~

i = the relevant interval;

S_i = number of seconds in interval i;

$RTLBMP_{p,i}$ = the real-time LBMP, in $/MWh, for interval i at Proxy Generator Bus p which is the source of the Import t supplied by Supplier u;

$DecBid_{u,\cancel{i}h}$ = the Decremental Bid, in $/MWh, ~~supplied by Supplier u~~ for Import t ~~for~~in ~~hour h~~hour h containing interval i;

$RTCen_{u,\cancel{i}h}$ = the scheduled Energy injections, in MWh, for ~~Supplier~~Import t in hour h ~~u in~~containing ~~hour h~~interval i as determined by Real-Time Commitment (RTC_{15}); and

$RTDen_{u,i}$ = the scheduled Energy injections, in MWh, for ~~Supplier u~~Import t in interval i as determined by Real-Time Dispatch (RTD).

Cost Recovery and Miscellaneous Provisions[39]

SCHEDULE 1 (OATT)

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Energy schedules for all Wheels Through and Exports. For the ISO Services Charge calculated pursuant to Sections 2.B.2, 2.B.3, and 2.B.4 of this Rate Schedule, the Transmission Customer's billing units shall be based on the Actual Energy Withdrawals for all Transmission Service to supply Load in the NYCA, and hourly Energy schedules for all Wheels Through and Exports. ~~To the extent Schedule 1 charges are associated with meeting the reliability needs of a local system, the billing units for such charges will be based on the Actual Energy Withdrawals in the sub-zone(s) where the Resource needed to meet the reliability need is located.~~[40] ~~To the extent Schedule 1 charges are associated with payments made for supplemental payments and Demand Reduction Incentive payments to Demand Reduction Providers, the billing units of such charges shall be based on Actual Energy Withdrawals to supply Load in the NYCA according to the methodology described in Attachment R.~~[41]

The following is newly stricken language as this remainder of sheet 232 is covered by new section 5 (B).

~~To the extent that the sum of all Bilateral Schedules, excluding schedules of Bilateral Transactions with Trading Hubs as their POWs, and all Day-Ahead Market purchases to service Load in the Day-Ahead schedule is less than the ISO's Day-Ahead forecast of Load and the ISO commits Resources in addition to the reserves it normally maintains to enable it to respond to contingencies to meet the ISO's Day-Ahead forecast of Load, charges associated with the costs of Bid Production Cost Guarantees for the additional Resources committed Day-Ahead to meet the ISO's Day-Ahead forecast of Load shall be allocated to Transmission Customers who are not bidding as Suppliers according to the Methodology described in Attachment T.~~

[39] General Note: The proposed tariff changes are indicated in this document in track changes, but certain formatting changes were made before editing these sheets: (i) headers and footers were removed, other than sheet numbers; (ii) double-spacing was converted to single-spacing, (iii) certain formatting and spacing between characters were revised. These changes will not show as track changes. In addition, some text was relocated for reorganization/clarification purposes, which relocation is noted only in footnotes. Additional explanatory footnotes are included throughout the text.

[40] The substance of this sentence has been relocated to Section 5.C of this Schedule 1 (Tariff Sheet 238).

[41] The substance of this sentence has been relocated to Section 5.A of this Schedule 1 (Tariff Sheet 238).

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for those taking services under Part IV of the OATT) as described in Section 2.A of this Rate Schedule. Charges to be paid by Transmission Customers for this service shall be aggregated to render a monthly charge.

b. Transmission Customers taking service under Part IV of the OATT to supply Station Power as third-party providers shall pay to the ISO a daily charge for this service equal to the product of (A) the sum of the daily bills for such facilities as described in subparagraph (a) above and (B) the ratio of the Transmission Customer's Station Power supplied under Part IV of the OATT for the day to the sum of all withdrawal billing units for the day.

c. The ISO shall credit charges paid for this service by Transmission Customers and LSEs taking service under Part IV of the OATT to supply Station Power as third-party providers for the day on a Load Ratio Share basis to Transmission Customers serving Load in the NYCA for the day.

4. Residual Adjustment ~~and Bid Production Guarantees Component~~

a. The ISO shall calculate, and Transmission Customers, other than Transmission Customers taking service under Part IV of the OATT to supply Station Power as third party providers, shall pay an hourly charge equal to the product of (A) the residual adjustment costs listed in Section 4.A of this Rate Schedule for each hour and (B) the ratio of (i) the Transmission Customer's withdrawal billing units for that hour as described in Section 2.A of this Rate Schedule to

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(ii) the sum of all ISO Transmission Customers' withdrawal billing units for that hour as described in Section 2A of this Rate Schedule.

b. The ISO shall calculate, and each Transmission Customer taking service under Part IV of the OATT to supply Station Power as a third party provider shall pay a daily charge equal to the product of (A) the residual adjustment costs listed in Section 4.A of this Rate Schedule for each day and (B) the ratio of (i) the withdrawal units of the Transmission Customer taking service under Part IV of the OATT to supply Station Power as a third party provider for that day to (ii) the sum of all ISO Transmission Customers' withdrawal billing units for that day as described in Section 2A of this Rate Schedule. The ISO shall credit revenue collected by application of this charge, on a Load ratio share basis, to all ISO Transmission Customers' withdrawal billing units as described in Section 2.2.A of this rate Schedule 1 summed for the day.

~~c. The ISO shall calculate, and each Transmission Customer shall pay, a daily charge equal to the product of (A) the bid production guarantee costs listed in Section 4.B of this Rate Schedule for each day and (B) the ratio of (i) the Transmission Customer's withdrawal billing units for that day as described in Section 2.A of this Rate Schedule to (ii) the sum of all ISO~~

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~~Transmission Customers' withdrawal billing units for that day as described in Section 2A of this Rate Schedule,[42] provided, however, that the costs of supplemental payments and Demand Reduction Incentive Payments made to Demand Reduction Providers shall be allocated to Transmission Customers according to the methodology described in Attachment R.[43]~~

The following is newly stricken language as this remainder of sheet 232 is covered by new section 5 (B).

~~To the extent that the sum of all Bilateral Schedules and all Day-Ahead Market purchases to serve Load in the Day-Ahead schedule is less than the ISO's Day-Ahead forecast of Load and the ISO commits Resources in addition to the reserves it normally maintains to enable it to respond to contingencies to meet the ISO's Day-Ahead forecast of Load, charges associated with the costs of Bid Production~~

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~~Cost Guarantees for the additional Resources committed Day-Ahead to meet the ISO's Day-Ahead forecast of Load shall be allocated to Transmission Customers who are not bidding as Suppliers according to the Methodology described in Attachment T.~~

The balance of the page remains

[42] The substance of this sentence has been relocated to Section 5.D of this Schedule 1 (Tariff Sheet 238).
[43] The substance of this sentence has been relocated to Section 5.A of this Schedule 1 (Tariff Sheet 238).

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- Costs that the ISO incurs as a result of bad debt, including finance charges;
- Refunds, if any, ordered by the Commission to be paid by the ISO, at the conclusion of Central Hudson Gas & Electric Corp., Docket Nos. ER97-1523- 011, OA97-470-010 and ER97-4234-008; and
- Regulatory fees.
- The ISO's share of the expenses of Northeast Power Coordinating Council, Inc. or its successor.

4. Residual Adjustment ~~and Bid Production Guarantees~~

~~A. Residual Adjustment~~

The ISO's payments from Transmission Customers will not equal the ISO's payments to Suppliers. Part of the difference consists of Day-Ahead Congestion Rent. The remainder comprises the Residual Adjustment, which will be an adjustment to the costs in Section 3A. The most significant components of the Residual Adjustment, which is calculated below, include:

- The greater revenue the ISO collects for Marginal Losses from Transmission Customers, in contrast to payments for losses remitted to generation facilities;
- Costs or savings associated with the ISO redispatch of Generators resulting from a change in Transfer Capability between the Day-Ahead schedule and the real-time dispatch;

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(iv) payments of the real-time TUC to Transmission Customers that reduced their schedules for that hour after the Day-Ahead commitment; (v) payments of Congestion Rents collected for that hour in the Day-Ahead schedule to Primary Holders of TCCs; (vi) settlements with Transmission Owners for losses revenue variances; and (vii) positive Net Congestion Rents collected in that hour.

~~B. Bid Production Guarantees~~

~~The ISO's costs also include the costs associated with differences between the amounts bid by generating facilities that have been committed and scheduled by the ISO to provide Energy and certain Ancillary Services, and the actual revenues received by these~~

~~generating facilities for providing such Energy and Ancillary Services. Where the costs are incurred to compensate a Resource for meeting the reliability needs of a local system, the associated charge shall apply only to Transmission Customers serving Load in the Load Zone(s) or sub-zone where the Resource is located.~~[44] ~~The ISO's costs also include the costs associated with payments made for supplemental payments and Demand Reduction Incentive payments to Demand Reduction Providers.~~[45]

5. Bid Production Cost Guarantee Payments and Demand Reduction Incentive Payments[46]

The ISO shall allocate on a daily basis the costs related to Bid Production Cost Guarantee payments in the following manner:

A. Costs of Demand Reduction BPCGs and Demand Reduction Incentive Payments

After accounting for imbalance charges paid by Demand Reduction Providers, the ISO shall allocate the costs associated with Demand Reduction BPCGs and Demand Reduction Incentive Payments to Transmission Customers pursuant to the methodology established in Attachment R of this ISO OATT.

B. Costs of BPCGs for Additional Generating Units Committed to Meet Forecast Load

If ~~To the extent that~~ the sum of all Bilateral Transaction ~~S~~schedules and all Day-Ahead Market purchases to serve Load in the Day-Ahead schedule is less than the ISO's Day-Ahead forecast of Load, ~~and~~ the ISO will commit~~s~~ Resources in addition to the reserves that it normally maintains to enable it to respond to contingencies to meet the ISO's Day-Ahead forecast of Load.~~,~~ The ISO shall allocate a portion of the costs ~~charges~~ associated with ~~the costs of~~ BPCGs~~id Production Cost Guarantees~~ for the additional Resources committed Day-Ahead to meet the ~~ISO's~~ Day-Ahead forecast of Load ~~shall be allocated~~ to Transmission Customers pursuant to the methodology established ~~who are not bidding as Suppliers according to the Methodology described~~ in Attachment T of this ISO OATT.[47] The ISO

[44] The substance of this sentence has been relocated to Section 5.C of this Schedule 1 (Tariff Sheet 238).
[45] The substance of this sentence has been relocated to Section 5.A of this Schedule 1 (Tariff Sheet 238).
[46] General Note: The provisions for the recovery of BPCG and Demand Reduction Incentive Payment costs are scattered throughout Schedule 1 of the OATT. We have relocated all of these provisions in Section 5 of Schedule 1 and clarified the descriptions of the different recovery methodologies. In relocating the provisions, care has been taken to not lose the substance of the provisions We have provided footnotes indicating the new location of all relocated provisions.
[47] This sentence was originally located in Section 2A of this Rate Schedule 1.

shall allocate the residual costs of such BPCGs not recovered through the methodology in Attachment T of the ISO OATT pursuant to Section 5.D of this Schedule 1.

C. Costs of BPCGs Resulting from Meeting the Reliability Needs of a Local System

The ISO shall allocate the costs for BPCGs incurred to compensate Suppliers for their Resources meeting the reliability needs of a local system only to Transmission Customers serving Load in the sub-zone where the Resource is located. To do so, the ISO shall assess to each Transmission Customer a daily charge for each sub-zone equal to the product of

(a) the BPCG costs for that day in that sub-zone arising as a result of meeting the reliability needs of the local system; and

(b) the ratio of (i) the Transmission Customer's withdrawal billing units (as described in Section 2.A of this Schedule 1) for that day in that sub-zone to (ii) the sum of all Transmission Customers' withdrawal billing units (as described in Section 2.A of this Schedule 1) for that day in that sub-zone.

D. Costs of All Remaining BPCGs

The ISO shall allocate the costs of all BPCGs not recovered through Sections 5.A, 5.B, or 5.C of this Schedule 1, including the residual costs of BPCGs for additional Resources not recovered through the methodology in Attachment T of this ISO OATT, among all Transmission Customers. To do so, the ISO shall assess to each Transmission Customer a daily charge equal to the product of

(a) the remaining BPCG costs for that day not recovered by the ISO through Sections 5.A, 5.B, or 5.C of this Schedule 1; and

(b) the ratio of (i) the Transmission Customer's withdrawal billing units (as described in Section 2.A of this Schedule 1) for that day to (ii) the sum of all Transmission Customers' withdrawal billing units (as described in Section 2.A of this Schedule 1) for that day.

6. Day-Ahead Margin Assurance Payments[48]

The ISO shall allocate, on an hourly basis, the costs related to Day-Ahead Margin Assurance Payments in the following manner:

A. Costs of DAMAPs Resulting from Meeting the Reliability Needs of a Local System

The ISO shall allocate the costs for DAMAPs incurred to compensate Resources for meeting the reliability needs of a local system only to Transmission Customers serving Load in the sub-zone where the Resource is located. To do so, the ISO shall assess to each Transmission Customer an hourly charge for each sub-zone equal to the product of

(a) the DAMAP costs for that hour in that sub-zone arising as a result of meeting the reliability needs of the local system; and

(b) the ratio of (i) the Transmission Customer's withdrawal billing units (as described in Section 2.A of this Schedule 1) for that hour in that sub-zone to (ii) the sum of all Transmission Customers' withdrawal billing units (as described in Section 2.A of this Schedule 1) for that hour in that sub-zone.

B. Costs of All Remaining DAMAPs

The ISO shall allocate the costs of all DAMAPs not recovered through Section 6.A of this Schedule 1 among all Transmission Customers. To do so, the ISO shall assess to each Transmission Customer an hourly charge equal to the product of:

(a) the remaining DAMAP costs for that hour not recovered by the ISO through Section 6.A; and

(b) the ratio of (i) the Transmission Customer's withdrawal billing units (as described in Section 2.A of this Schedule 1) for that hour in the NYCA ~~plus Exports and Wheels Through~~ to (ii) the sum of all Transmission Customers' withdrawal

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48 The NYISO Tariffs do not currently provide an explicit description of the method by which the NYISO recovers Day-Ahead Margin Assurance Payment costs through Rate Schedule 1. This Section 6 of Schedule 1 of the OATT provides clarification.

billing units (as described in Section 2.A of this Schedule 1) for that hour in the NYCA ~~plus Exports and Wheels Through~~.

7. Import Curtailment Guarantee Payments[49]

The ISO shall allocate, on an hourly basis, the costs of all Import Curtailment Guarantee Payments paid to Import Suppliers among all Transmission Customers. To do so, the ISO shall assess to each Transmission Customer an hourly charge equal to the product of

(a) the costs for the Import Curtailment Guarantee Payments for that hour; and

(b) the Transmission Customer's withdrawal billing units (as described in Section 2.A of this Schedule 1) for that hour in the NYCA ~~plus Exports and Wheels Through~~ to (ii) the sum of all Transmission Customers' withdrawal billing units (as described in Section 2.A of this Schedule 1) for that hour in the NYCA ~~plus Exports and Wheels Through~~.

[49] The NYISO Tariffs do not currently provide an explicit description of the method by which the NYISO recovers Import Curtailment Guarantee Payment costs through Rate Schedule 1. This Section 7 of Schedule 1 of the OATT provides clarification.

ATTACHMENT T
COST ALLOCATION METHODOLOGY FOR SCHEDULE 1 BID PRODUCTION GUARANTEES FOR ADDITIONAL GENERATING UNITS COMMITTED TO MEET FORECAST LOAD

The Day-Ahead commitment of generating units includes sufficient ~~Generators and/or Interruptible Load~~Resources to provide for the safe and reliable operation of the NYS Power System. In cases in which the sum of all Day-Ahead Bilateral Schedules~~ and all Day-Ahead~~, purchases and sales of energy within the NYCA is less than the ISO's Day-Ahead forecast of Load, the ISO will commit Resources in addition to the reserves it normally maintains ~~to enable it to respond to contingencies~~ ("Additional Resources"). Payments for Bid Production Cost ~~Guarantees~~ Guarantees ("BPCG") made to such ~~additional~~ Additional Resources are to be ~~recovered under Schedule 1 of the OATT. These "BPCG to Additional Resources" shall be~~ allocated~~ to Transmission Customers, to the extent they are not acting as Suppliers,~~ pursuant to the methodology set forth below and recovered under Rate Schedule 1 of the OATT~~, on the basis of their Real-Time energy purchases in their Load Zones or Composite Load Zones (see below). By design, when the NYISO forecast load exceeds actual load, the methodology below will only be used to allocate part of the BPCG to Additional Resources~~. Any BPCG payments made to Additional Resources that are not allocated pursuant to this methodology ~~residual~~ shall be allocated to Transmission Customers according to the provisions of Rate Schedule 1, Section 4.B of the OATT.

For purposes of this Attachment T, “Eligible Transmission Customers” are Transmission Customers that are scheduled to sell Energy at a Load bus specified for Virtual Transactions in the Day-Ahead Market and Transmission Customers purchasing load in the real-time market at a Load bus not a Load bus specified for Virtual Transactions and not a Proxy Generator Bus. Load Zones and composite Load Zones used in the allocation of Bid Production Cost Guarantee payments made to Additional Resources are initially set as: (i) Load Zones A-E, (ii) Load Zones F-I, (iii) Load Zone J, and (iv) Load Zone K and may be adjusted by the ISO to reflect the most frequently constrained transmission interfaces in the NYCA.

~~More specifically,~~ BPCG payments made to Additional Resources shall be allocated to each Eligible Transmission Customer~~, to the extent that Transmission Customer is not acting as a Supplier~~ as follows:

$$BPCG_c = BPCG_{NYCA} \times \sum_{L \in NYCA} \left(K_L^{fe} \times K_L^{loc} \times K_{c,L}^{customer} \right)$$

Where:

$BPCG_c$	Obligation of Transmission Customer “c” for the Bid Production Cost Guarantees for ~~such a~~Additional ~~resources~~Resources for the day.
$BPCG_{NYCA}$	Total Bid Production Cost Guarantees~~ in the NYCA for~~ ~~such a~~paid to Additional ~~resources~~Resources in the NYCA for the day.
c	An Eligible Transmission Customer
L	Load Zone or Composite Load Zone
K^{fe}_L	A scale factor calculated for each Load Zone or Composite Load Zone that determines the portion of BPCG to Additional Resources that will

	be allocated through the procedures described in this attachment.
K^{loc}_{L}	A scale factor calculated for each Load Zone or Composite Load Zone "L" ~~"L"~~ that determines the share of BPCG to Additional Resources that shall be allocated to that Load Zone or Composite Load Zone. The scale factor is based on the ratio of Energy purchases in the real-time market by Eligible Transmission Customers in load zone or composite load zone "L" in each hour, summed over the hours of the day in which these purchases are positive, to all Energy purchases in the real-time market by Eligible Transmission Customers in the NYCA in each hour, summed over the hours of the day in which these purchases are positive.
$K^{customer}_{c,L}$	A scale factor calculated for Eligible Transmission Customer "c" in Load Zone or Composite Load Zone "L" which determines the portion of the BPCG to Additional Resources allocated to that Load Zone or Composite Load Zone ~~distributed according to the methodology set forth in this attachment~~ that shall be allocated to that Eligible Transmission ~~c~~Customer- "c."

RTP^{act}_{L}	~~Net purchases of e~~Energy purchases from the Real-Time market in Load Zone or Composite Load Zone "L" by all Eligible Transmission Customers ~~energy purchases in the Real-Time markets in Load Zone or Composite Load Zone "L" by Eligible Transmission Customers in each hour in which these purchases are positive; summed over the hours of the day~~ ~~to the extent they are not acting as Suppliers,~~ in each hour, summed over the hours of the day in which these purchases are positive.
$RTP^{act}_{c,L}$	~~Purchases of e~~Energy purchases from the Real-Time market in Load Zone or Composite Load Zone "L" by an Eligible Transmission Customer "c~~,~~" ~~to the extent that customer is not acting as a Supplier, to meet obligations arising from the Day-Ahead sale of energy, in each hour; plus energy purchases in the Real-Time markets by Customer "c," to the extent that customer is not acting as a Supplier, excluding purchases to meet obligations arising from the Day Ahead market,~~ in each hour summed over hours of the day in which these purchases are positive;~~ summed over each hours of the day~~.
RTP^{fcst}_{L}	The sum of (1) Day-Ahead sales for each hour of the day in the Day-Ahead market at the Load bus specified for Virtual Transactions ~~of virtual energy~~ in Load Zone or Composite Load Zone "L" by Eligible Transmission Customers~~, to the extent they are not acting as Suppliers,~~ ; and (2) ~~-~~the ISO's Day-Ahead forecast Load requirement ~~forecast load~~ for Load Zone or Composite Load Zone "L" for that hour of the day less the sum of (i) Energy purchases ~~of energy~~ from the Day-Ahead market at Load buses including Load buses specified for Virtual Transactions but not Proxy Generator Buses and Bilateral Transactions to Load Buses other than those specified for Virtual Transactions and other than Proxy Generator Buses for that hour~~,~~ ; summed over the hours of the day in which the sum of (1) and (2) is positive.

K^{fe}_{L} shall be calculated as shown below except that ~~the value zero shall be used if the expression below yields a negative number and~~ the value one shall be used if the expression yields a number greater than one.

$$K_L^{fe} = \frac{RTP_L^{act}}{RTP_L^{fcst}}$$

K^{loc}_L shall be calculated as shown below.

$$K_L^{loc} = \frac{RTP_L^{act}}{\sum_{L \in NYCA} RTP_L^{act}}$$

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$K^{customer}_{c,L}$ shall be calculated as shown below.

$$K^{customer}_{c,L} = \frac{RTP^{act}_{c,L}}{\sum_{c \in L} RTP^{act}_{c,L}}$$

The residual ~~between Bid Production Cost Guarantee~~BPCG payments not allocated to such ~~additional~~ Additional Resources ~~not allocated~~ according to the methodology described above shall be allocated to all Transmission Customers using the methods described in Schedule 1, Section 4.B. The residual is determined according to:

$$BPCG_{NYCA} - \sum_{c \in NYCA} BPCG_c$$

~~Load Zones and Composite Load Zones used in the allocation of Bid Production Cost Guarantees for such additional resources are initially set as: (i) Load Zones A-E, (ii) Load Zones F-I, (iii) Load Zone J, and (iv) Load Zone K and may be adjusted by the ISO to reflect the most frequently constrained transmission interfaces in the NYCA.~~