18 Attachment C -Formulas For Determining Bid Production Cost Guarantee Payments

18.1 Introduction

Ten Bid Production Cost Guarantee (BPCG) payments for eligible Suppliers are described in this attachment: (i) a Day-Ahead BPCG for Generators; (ii) a Day-Ahead BPCG for Imports; (iii) a real-time BPCG for Generators and Aggregations in RTD intervals other than Supplemental Event Intervals; (iv) a BPCG for Generators and Aggregations for Supplemental Event Intervals; (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) whose start is 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 and / or Regulation Service in the Day-Ahead Market; and (x) a BPCG for Demand Side Resources providing synchronized Operating Reserves and / or Regulation Service in the Real-Time Market. Suppliers shall be eligible for these payments in accordance with the eligibility requirements and formulas established in this Attachment C.

The Bid Production Cost guarantee payments described in this Attachment C are each calculated and paid independently from each other. A Customer's eligibility to receive one type of Bid Production Cost guarantee payment shall have no impact on the Customer's eligibility to be considered to receive another type of Bid Production Cost guarantee payment, in accordance with the rule set forth in this Attachment C.

18.2 Day-Ahead BPCG For Generators and Aggregations

18.2.1 Eligibility to Receive a Day-Ahead BPCG for Generators and Aggregations

18.2.1.1 Eligibility.

A Supplier that bids on behalf of an ISO-Committed Fixed Generator or an ISO Committed Flexible Generator or an ISO-Committed Flexible Aggregation that is committed by the ISO in the Day-Ahead Market shall be eligible to receive a Day-Ahead Bid Production Cost guarantee payment. Energy Storage Resources and Aggregations comprised entirely of Energy Storage Resources that satisfy this eligibility criteria shall be eligible to receive a Day-Ahead Bid Production Cost guarantee payment regardless of whether the Resource Self-Manages its Energy Level.

18.2.1.2 Non-Eligibility (includes both partial and complete exclusions).

Notwithstanding Section 18.2.1.1, a Supplier that bids on behalf of an ISO-Committed Fixed Generator or an ISO-Committed Flexible Generator, or an ISO-Committed Flexible Aggregation, that is committed by the ISO in the Day-Ahead Market shall not be eligible to receive a Day-Ahead Bid Production Cost guarantee payment if that Generator or Aggregation has been committed in the Day-Ahead Market for any other hour of the day as a result of a Self-Committed Fixed or Self-Committed Flexible bid.

Notwithstanding Section 18.2.1.1, Incremental Energy Bid costs and Minimum Generation Bids that exceed $1,000/MWh are only eligible for inclusion in a Day-Ahead Bid Production Cost guarantee payment in accordance with Sections 21.4.1 and 23.7 of this ISO Services Tariff.

18.2.2 Formulas for Determining Day-Ahead BPCG for Generators and Aggregations

18.2.2.1 Applicable Formula. A Supplier's BPCG for Generator or Aggregation g, shall be as follows:

Day-Ahead Bid Production Cost Guarantee for Generator g or Aggregation g =

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

18.2.2.2 Variable Definitions. The terms used in this Section 18.2.2 shall be defined as follows:

$Supplier_g$ = Generator *g* or Aggregation *g*;

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

EH_{gh}^{DA} = Energy scheduled Day-Ahead to be provided by Supplier *g* or withdrawn by Supplier g, which is eligible to withdraw Energy,in hour *h* expressed in terms of MWh;

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

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

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

If Supplier g was committed in the Day-Ahead Market, or in the Real-Time Market via Supplemental Resource Evaluation ("SRE"), on the day prior to the Dispatch Day and Supplier g has not yet completed the minimum run time reflected in the accepted Bid for the hour in which it was scheduled to start on the day before the Dispatch Day (as mitigated, where appropriate), then Supplier g shall have its minimum generation cost set equal to the revenues received for energy produced at its minimum operating level for purposes of calculating a Day-Ahead Bid Production Cost guarantee until Supplier g completes the

minimum run time reflected in the accepted Bid for the hour in which it was scheduled to start on the day before the Dispatch Day;

SUC_{gh}^{DA} = Start-Up Bid by Supplier *g* in hour *h,* or when applicable the mitigated Start-Up Bid for Supplier *g,* in hour *h* in the Day-Ahead Market expressed in terms of $/start; *provided, however*, that the Start-Up Bid for Supplier *g* in hour *h* or, when applicable, the mitigated Start-Up Bid, for Supplier *g* in hour *h*, may be subject to *pro rata* reduction in accordance with the rules set forth in Section 18.12 of this Attachment C. Bases for *pro rata* reduction include, but are not limited to, failure to be scheduled, and to operate in real-time to produce, in each hour, the MWh specified in the accepted Minimum Generation Bid that was submitted for the first hour of Generator g's Day-Ahead or SRE schedule, and failure to operate for the minimum run time specified in the Bid submitted for the first hour of Supplier *g*'s Day-Ahead or SRE schedule.

If Supplier *g* was committed in the Day-Ahead Market, or in the Real-Time Market via SRE, on the day prior to the Dispatch Day, *and* Supplier g has not yet completed the minimum run time reflected in the accepted Bid for the hour in which it was scheduled to start on the day before the Dispatch Day (as mitigated, where appropriate) plus the contiguous hour that follows the conclusion of such minimum run time, *then* Supplier *g* shall have its Start-Up Bid set to zero for purposes of calculating a Day-Ahead Bid Production Cost guarantee.

For a long start-up time Supplier (*i.e.*, a Supplier 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 Supplier g in hour h shall be the Supplier's Start-Up Bid, or when applicable the mitigated Start-Up Bid for Supplier g, for the hour (as determined at the point in time in which the ISO provided notice of the request for start-up):

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

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

$NASR_{gh}^{DA}$ = Net Ancillary Services revenue*,* expressed in terms of $*,* paid to Supplier g as a result of having been committed to produce Energy for the LBMP Market and/or Ancillary Services Day-Ahead in hour h which is computed by summing the following: (1) Voltage Support Service payments received by that Supplier 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 Supplier for all Regulation Service it is scheduled Day-Ahead to provide in that hour, less that Supplier's Day-Ahead Regulation Capacity Bid to provide that amount of Regulation Service in that hour; and (3) payments made to that Supplier 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 Supplier's

Day-Ahead Bid to provide Spinning Reserve and synchronized 30-Minute Reserve in that hour.

18.3 Day-Ahead BPCG For Imports

18.3.1 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 Bid Production Cost guarantee payment.

18.3.2 BPCG Calculated by Transaction ID

For purposes of calculating a Day-Ahead Bid Production Cost guarantee payment for an Import under this Section 18.3, 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.

18.3.3 Formula for Determining Day-Ahead BPCG for Imports

Day-Ahead Bid Production Cost guarantee for Import t by Supplier =

$$max\left[\sum_{h=1}^{N}\left(DecBid_{th}^{DA} - LBMP_{th}^{DA}\right) * SchImport_{th}^{DA}, 0\right]$$

Where;

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

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

$LBMP_{th}^{DA}$ = Day-Ahead LBMP, in $/MWh, for hour h at the Proxy Generator Bus that is the source of the Import t and

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

18.4 Real-Time BPCG For Generators and Aggregations In RTD Intervals Other Than Supplemental Event Intervals

18.4.1 Eligibility for Receiving Real-Time BPCG for Generators and Aggregations in RTD Intervals Other Than Supplemental Event Intervals

18.4.1.1 Eligibility.

A Supplier shall be eligible to receive a real-time Bid Production Cost guarantee payment for intervals (excluding Supplemental Event Intervals) if it bids on behalf of:

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

18.4.1.1.2 a Self-Committed Flexible Generator if the Generator's minimum operating level does not exceed its Day-Ahead schedule at any point during the Dispatch Day; or

18.4.1.1.3 a Generator or Aggregation committed via SRE, or committed or dispatched by the ISO as Out-of-Merit generation to ensure NYCA or local system reliability for the hours of the day that it is committed via SRE or is committed or dispatched by the ISO as Out-of-Merit generation to meet NYCA or local system reliability without regard to the Bid mode(s) employed during the Dispatch Day, except as provided in Sections 18.4.2 and 18.12, below.

18.4.1.1.4 an ISO-Committed Flexible Aggregation comprised entirely of Energy Storage Resources that Self-Manages its Energy Level.

18.4.1.2 Non-Eligibility (includes both partial and complete exclusions).

18.4.1.2.1 Notwithstanding Section 18.4.1.1, a Supplier that bids on behalf of an ISO-Committed Fixed Generator or an ISO-Committed Fixed Aggregation or an ISO-Committed Flexible Generator that is committed by the ISO in the Real-Time Market shall not be eligible to

receive a real-time Bid Production Cost guarantee payment if that Generator or Aggregation has been committed in real-time, in any other hour of the day, as the result of a Self-Committed Fixed bid or a Self-Committed Flexible bid with a minimum operating level that exceeds its Day-Ahead schedule, *provided however*, a Generator or Aggregation that has been committed in real time as a result of a Self-Committed Fixed bid, or a Self-Committed Flexible bid with a minimum operating level that exceeds its Day-Ahead schedule will not be precluded from receiving a real-time Bid Production Cost guarantee payment for other hours of the Dispatch Day, in which it is otherwise eligible, due to these Self-Committed mode Bids if such Bid mode was used for: (i) an ISO authorized Start-Up, Shutdown or Testing Period, or (ii) for hours in which such Generator or Aggregation was committed via SRE, or committed or dispatched by the ISO as Out-of-Merit to meet NYCA or local system reliability as long as the Generator's Out-of-Merit Upper Operating Limit is equal to or greater than any Self-Committed minimum operating level.

18.4.1.2.2 Notwithstanding Section 18.4.1.1, Incremental Energy Bid costs and Minimum Generation Bids that exceed $1,000/MWh are only eligible for inclusion in a real-time Bid Production Cost guarantee payment for intervals other than Supplemental Event Intervals, in accordance with Sections 21.4.1 and 23.7 of this ISO Services Tariff.

18.4.1.2.3 Notwithstanding Section 18.4.1.1, an Energy Storage Resource or Aggregation comprised entirely of Energy Storage Resources with a ISO-Managed Energy Level for any hour of the Real-Time Market day shall not be eligible to receive a real-time Bid Production Cost guarantee payment for that day, provided however, an Energy Storage Resource or Aggregation comprised entirely of Energy Storage Resources shall be eligible for a real-time

Bid Production Cost guarantee payment in accordance with Section 18.4.1.1.3 of this ISO Services Tariff regardless of whether the Energy Level is ISO-Managed.

18.4.1.2.4 Notwithstanding Section 18.4.1.1, Energy Storage Resources and Aggregations shall not be eligible to receive a real-time Bid Production Cost guarantee payment for a day if such Resources' Real-Time Market Bids for any hour of that day do not permit the Resource to receive a schedule of zero MW. However, such Resources shall be eligible for a real-time Bid Production Cost guarantee payment in accordance with Section 18.4.1.1.3 of this ISO Services Tariff.

18.4.2 Formula for Determining Real-Time BPCG for Generators and Aggregations in RTD Intervals Other Than Supplemental Event Intervals

Real-Time Bid Production Cost Guarantee for Supplier g, which is not an Energy Storage Resource or an Aggregation that contains Energy Storage Resource(s) =

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

Real-Time Bid Production Cost Guarantee for Supplier g, which is an Energy Storage Resource or an Aggregation that contains Energy Storage Resource(s) =

$$Max\left(0, \sum_{i\in M}(InjBPCG_{gi} + WthBPCG_{gi})\right)$$

where, when an Energy Storage Resource or an Aggregation that contains Energy Storage Resource(s) has a real-time schedule to inject Energy:

$$InjBPCG_{gi} = \left(\left(\int_{max\left(EI_{gi}^{DA},0\right)}^{EI_{gi}^{RT}} C_{gi}^{RT} - LBMP_{gi}^{RT} * \left(EI_{gi}^{RT} - max\left(EI_{gi}^{DA},0\right)\right) \right) * \frac{S_i}{3600} \right)$$

$$- \left(NASR_{gi}^{TOT} - NASR_{gi}^{DA}\right) - RRAP_{gi} + RRAC_{gi}$$

and, when an Energy Storage Resource or an Aggregation that contains Energy Storage Resource(s) has a real-time schedule to withdraw Energy =

$$WthBPCG_{gi} = \left(\left(\int_{min\left(EI_{gi}^{DA},0\right)}^{EI_{gi}^{RT}} C_{gi}^{RT} - LBMP_{gi}^{RT} * \left(EI_{gi}^{RT} - min\left(EI_{gi}^{DA},0\right)\right) \right) * \frac{S_i}{3600} \right)$$

$$- \left(NASR_{gi}^{TOT} - NASR_{gi}^{DA}\right) - RRAP_{gi} + RRAC_{gi}$$

where:

$Supplier_g$ = Generator *g* or Aggregation *g*;

S_i = number of seconds in RTD interval i;

C_{gi}^{RT} = Bid cost submitted by Supplier g, or when applicable the mitigated Bid cost for Supplier g, in the RTD for the hour that includes RTD interval i expressed in terms of $/MWh, except in intervals in which the dispatch of the Supplier is constrained by its downward ramp rate for that interval, unless that Supplier was scheduled to provide Regulation Service in that interval and its RTD basepoint was less than its AGC basepoint, and except in hours in which the NYISO has increased Supplier g's minimum operating level, either (i) at the Supplier's request including through an adjustment to the Resource's self-commitment schedule, or (ii) in order to reconcile the ISO's dispatch with the Supplier's actual output or to address reliability concerns that arise because the Supplier is not following Base Point Signals, in which case C_{gi}^{RT} shall be deemed to be zero;

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

MGC_{gi}^{RT} = Minimum Generation Bid by Supplier g, or when applicable the mitigated Minimum Generation Bid for Supplier g, in the Real-Time Market for the hour that includes RTD interval i, expressed in terms of $/MWh, which Bid or mitigated Bid may include costs pursuant to Section 4.1.8;

If Supplier g was committed in the Day-Ahead Market, or in the Real-Time Market via Supplemental Resource Evaluation ("SRE"), on the day prior to the Dispatch Day *and* Supplier g has not yet completed the minimum run time reflected in the accepted Bid for the hour in which it was scheduled to start on the day before the Dispatch Day (as mitigated, where appropriate), *then* Supplier g shall have its minimum generation cost set equal to the revenues received for energy produced at its minimum operating level for purposes of calculating a Real-Time Bid Production Cost guarantee until Supplier g completes the minimum run time reflected in the accepted Bid for the hour in which it was scheduled to start on the day before the Dispatch Day;

SUC_{gj}^{RT} = Start-Up Bid by Supplier g, or when applicable the mitigated Start-Up Bid for Supplier g, for hour j into RTD expressed in terms of $/start, which Bid or mitigated Bid may include costs pursuant to Section 4.1.8;

provided, however,

(i) the Start-Up Bid shall be deemed to be zero for (1) Self-Committed Fixed and Self-Committed Flexible Suppliers, (2) Suppliers 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) Suppliers 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;

(ii) if a Supplier 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 Supplier's Start-Up Bid included in its daily real-time Bid 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) if a Supplier has been committed via SRE and its SRE schedule immediately precedes or follows a real-time schedule that resulted from a Day-Ahead commitment, then the Supplier's Start-Up Bid included in its daily real-time Bid Production Cost guarantee calculation for this contiguous real-time commitment period shall be set to zero;

(iv) the real-time Start-Up Bid for Supplier g for hour j or, when applicable, the mitigated real-time Start-Up Bid, for Supplier g for hour j, may be subject to *pro rata* reduction in accordance with the rules set forth in Section 18.12 of this Attachment C. Bases for *pro rata* reduction include, but are not limited to, failure to be scheduled and operate in real-time to produce, in each hour, the MWh specified in the accepted Minimum Generation Bid that was submitted for the first hour of Supplier g's Day-Ahead or SRE schedule, and failure to operate for the minimum run time specified in the Bid submitted for the first hour of Supplier g's Day-Ahead or SRE schedule; and

(v) if Supplier g was committed in the Day-Ahead Market, or in the Real-Time Market via SRE, on the day prior to the Dispatch Day, *and* Supplier g has not yet completed the minimum run time reflected in the accepted Bid for the hour in which it was scheduled to start on the day before the Dispatch Day (as mitigated, where appropriate) plus the contiguous hour that follows the conclusion of such minimum run time, *then* Supplier g shall have its Start-Up Bid set to zero for purposes of calculating a Real-Time Bid Production Cost guarantee.

$NSUI_{gj}^{RT}$ = number of times Supplier g started up in hour j;

$NSUI_{gj}^{DA}$ = number of times Supplier g is scheduled Day-Ahead to start up in hour j;

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

M = the set of eligible RTD intervals in the Dispatch Day consisting of all of the RTD intervals in the Dispatch Day except:

(i) Supplemental Event Intervals (which are addressed separately in Section 18.5 below);

(ii) intervals during authorized Start-Up Periods, Shutdown Periods, or Testing Periods for Supplier g;

L = the set of all hours in the Dispatch Day

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

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

(ii) if otherwise, then $\max(\min(AE_{ig},RTSen_{ig}),EOP_{ig})$.

EI_{gi}^{DA} = Energy scheduled in the Day-Ahead Market to be provided or withdrawn by Supplier g in the hour that includes RTD interval i expressed in terms

of MW;

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

AE_{ig} = either, (1) when scheduled to withdraw, average Energy injections plus average Demand Reductions minus average Energy withdrawals by Supplier g in interval i but not more than $RTSen_{ig}$ plus any Compensable Overgeneration expressed in terms of MW; or (2) otherwise, average Energy injections plus average Demand Reductions minus average Energy withdrawals by Generator g in interval i expressed in terms of MW;

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

$NASR_{gi}^{TOT}$ = Net Ancillary Services revenue, expressed in terms of $, paid to Supplier 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 Supplier for that RTD interval, if it is not a Supplier of Installed Capacity; (2) Regulation Service payments that would be made to that Supplier for that hour based on a Performance Index of 1, less the Regulation Capacity and Regulation Movement Bids placed by that Supplier 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; (3) payments made to that Supplier for providing Spinning Reserve or synchronized 30-Minute Reserve in that hour, less the Bid placed by that Supplier 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 Supplier in that hour as a result of reducing that Supplier'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 Supplier g in RTD interval i expressed in terms of $.

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

18.4.3 Bids Used For Intervals at the End of the Hour

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 BPCG in Section 18.4.2 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 BPCG in Section 18.4.2 will be the Bid for the next hour, in accordance with ISO Procedures.

18.5 BPCG For Generators and Aggregations In Supplemental Event Intervals

18.5.1 Eligibility for BPCG for Generators and Aggregations in Supplemental Event Intervals

18.5.1.1 Eligibility

For intervals in which the ISO has called a large event reserve pick-up, as described in Section 4.4.4.1.1 of this ISO Services Tariff, or an emergency under Section 4.4.4.1.2 of this ISO Services Tariff, any Supplier who meets the eligibility requirements for a real-time Bid Production Cost guarantee payment described in subsection 18.4.1.1 of this Attachment C, shall be eligible to receive a BPCG under this Section 18.5.

18.5.1.2 Non-Eligibility (includes both partial and complete exclusions)

(A) Notwithstanding subsection 18.5.1.1, a Supplier shall not be eligible to receive a Bid Production Cost guarantee payment for Supplemental Event Intervals if the Supplier is not eligible for a real-time Bid Production Cost guarantee payment for the reasons described in Section 18.4.1.2 of this Attachment C.

(B) Notwithstanding subsection 18.5.1.1, Incremental Energy Bid costs and Minimum Generation Bids that exceed $1,000/MWh are only eligible for inclusion in a real-time Bid Production Cost guarantee payment for Supplemental Event Intervals, in accordance with Sections 21.4.1 and 23.7 of this ISO Services Tariff.

18.5.1.3 Additional Eligibility

Notwithstanding Section 18.5.1.2(A), a Supplier shall be eligible to receive a Bid Production Cost guarantee payment for a Generator or Aggregation providing energy during Supplemental Event Intervals occurring as a result of an ISO emergency under Section 4.4.4.1.2 of this ISO Services Tariff regardless of bid mode used for the day.

18.5.2 Formula for Determining BPCG for Generators and Aggregations in Supplemental Event Intervals

Real-Time Bid Production Cost Guarantee Payment for Generator or Aggregation g, which is not an Energy Storage Resource or an Aggregation that contains Energy Storage Resource(s) =

$$\sum_{i \in P}\left(\max\left(\begin{array}{c}\left(\int_{max\left(EI_{gi}^{DA},MGI_{gi}^{RT}\right)}^{max\left(EI_{gi}^{RT},MGI_{gi}^{RT}\right)} C_{gi}^{RT} + MGC_{gi}^{RT} * \left(MGI_{gi}^{RT} - MGI_{gi}^{DA}\right)\right) * \frac{S_i}{3600} \\ - LBMP_{gi}^{RT} * \left(EI_{gi}^{RT} - EI_{gi}^{DA}\right) - \left(NASR_{gi}^{TOT} - NASR_{gi}^{DA}\right) - RRAP_{gi} + RRAC_{gi}\end{array}\right), 0\right)$$

Real-Time Bid Production Cost Guarantee for Supplier g, which is an Energy Storage Resource or an Aggregation that contains Energy Storage Resource(s) =

$$Max\left(0, \sum_{i \in P}(InjBPCG_{gi} + WthBPCG_{gi})\right)$$

where, when an Energy Storage Resource or an Aggregation that contains Energy Storage Resource(s) has a real-time schedule to inject Energy:

$$InjBPCG_{gi} = \left(\left(\int_{max\left(EI_{gi}^{DA},0\right)}^{EI_{gi}^{RT}} C_{gi}^{RT} - LBMP_{gi}^{RT} * \left(EI_{gi}^{RT} - max\left(EI_{gi}^{DA},0\right)\right)\right) * \frac{S_i}{3600}\right)$$
$$- \left(NASR_{gi}^{TOT} - NASR_{gi}^{DA}\right) - RRAP_{gi} + RRAC_{gi}$$

and, when an Energy Storage Resource or an Aggregation that contains Energy Storage Resource(s) has a real-time schedule to withdraw Energy =

$$WthBPCG_{gi} = \left(\left(\int_{min\left(EI_{gi}^{DA},0\right)}^{EI_{gi}^{RT}} C_{gi}^{RT} - LBMP_{gi}^{RT} * \left(EI_{gi}^{RT} - min(EI_{gi}^{DA},0)\right) \right) * \frac{S_i}{3600} \right)$$

$$- \left(NASR_{gi}^{TOT} - NASR_{gi}^{DA}\right) - RRAP_{gi} + RRAC_{gi}$$

where:

$Supplier_g$ = Generator g or Aggregation g;

P = the set of Supplemental Event Intervals 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, for Suppliers in the location for which the maximum generation pickup has been called -- the average Actual Energy Injections, expressed in MWh, for Generator g in interval i, and for all other Suppliers EI_{gi}^{RT} is as defined in Section 18.4.2 above.

(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 18.4.2 above.

C_{gi}^{RT} = Bid cost submitted by Supplier g, or when applicable the mitigated Bid cost for Supplier 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 Supplier g's minimum operating level, either (i) at the Supplier's request, or (ii) in order to reconcile the ISO's dispatch with the Supplier's actual output or to address reliability concerns that arise because the Supplier is not following Base Point Signals, in which case C_{gi}^{RT} shall be deemed to be zero;

The definition of all other variables is identical to those defined in Section 18.4 above.

In the event that the ISO re-institutes penalties for poor Regulation Service performance under Section 15.3.8 of Rate Schedule 3 such penalties will not be taken into account when calculating supplemental payments under this Attachment C.

18.6 Real-Time BPCG For External Transactions

External Transactions are not eligible to receive Bid Production Cost guarantee payments in the Real-Time Market.

18.7. BPCG for Long Start-Up Time Generators Whose Starts are Aborted by the ISO Prior to their dispatch

18.7.1 Eligibility for BPCG for Long Start-Up Time Generators Whose Starts 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 whose start 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 Bid Production Cost guarantee payment under this Section 18.7.

18.7.2 Methodology for Determining BPCG for Long Start-Up Time Generators Whose Starts are Aborted by the ISO Prior to their Dispatch

A Supplier whose long start-up time Generator's start-up is aborted shall receive a prorated portion of its Start-Up Bid submitted for the hour in which the ISO requested that the Generator begin its start-up sequence, based on the portion of the start-up sequence that it has completed prior to the signal to abort the start-up (*e.g.,* if a long start-up time Generator 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 Start-Up Bid).

18.8 BPCG For Demand Reduction In The Day-Ahead Market

18.8.1 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 Bid Production Cost guarantee payment under this Section 18.8. However, incremental Curtailment Bid costs and minimum Curtailment initiation Bids that exceed $1,000/MWh are only eligible for inclusion in a Day-Ahead Bid Production Cost guarantee payment in accordance with Sections 21.4.1 and 23.7 of this ISO Services Tariff.

18.8.2 Formula for Determining BPCG for Demand Reduction in the Day-Ahead Market

Day-Ahead BPCG for Demand Reduction Provider d =

$$Max\left(\sum_{h=1}^{N}\left(MinCurCost_d^h + IncrCurCost_d^h - CurRev_d^h\right) + CurInitCost_d, 0\right)$$

where:

$$CurInitCost_d = \left(\sum_{h=1}^{N}\left(Min\left(ActCur_d^h, SchdCur_d^h\right)\right) / \left(\sum_{h=1}^{N} SchdCur_d^h\right)\right) * CurCost_d$$

$$MinCurCost_d^h = Min\left(\left(max\left(ActCur_d^h, 0\right), MinCur_d^h\right)\right) * MinCurBid_d^h$$

$$IncrCurCost_d^h = \left(\int_{MinCur_d^h}^{max\left(MinCur_d^h, min\left(SchdCur_d^h, ActCur_d^h\right)\right)} IncrCurBid_d^h\right)$$

$$CurRev_d^h = LBMP_{dh}^{DA} * min\left(max\left(ActCur_d^h, 0\right), SchdCur_d^h\right)$$

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.

18.9 BPCG For Special Case Resources

18.9.1 Eligibility for Special Case Resources BPCG

Any Supplier that bids a Special Case Resource that is committed by the ISO for an event in the Real-Time Market shall be eligible to receive a Bid Production Cost guarantee payment under this Section 18.9. Suppliers shall not be eligible for a Special Case Resource Bid Production Cost guarantee payment for the period over which a Special Case Resource is performing a test.

18.9.2 Methodology for Determining Special Case Resources BPCG

A Special Case Resource Bid Production Cost guarantee payment 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, 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.

18.10 BPCG For Demand Side Resources Providing Synchronized Operating Reserves and / or Regulation Service In The Day-Ahead Market

18.10.1 Eligibility for BPCG for Demand Side Resources Providing Synchronized Operating Reserves and / or 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/or Regulation Service in the Day-Ahead Market shall be eligible to receive a Bid Production Cost guarantee payment under this Section 18.10.

18.10.2 Formula for Determining BPCG for Demand Side Resources Providing Synchronized Operating Reserves and / or Regulation Service in the Day-Ahead Market

A Bid Production Cost guarantee payment to a Demand Side Resource with a synchronized Operating Reserves and/or Regulation Service schedule in the Day-Ahead Market shall be calculated as follows:

BPCG for Demand Side Resource d Providing synchronized Operating Reserves and/or Regulation Service Day-Ahead =

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

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 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 Regulation Capacity Bid to provide that amount of Regulation Service in that hour; 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.

18.11 BPCG For Demand Side Resources Providing Synchronized Operating Reserves and / or Regulation Service In The Real-Time Market

18.11.1 Eligibility for BPCG for Demand Side Resources Providing Synchronized Operating Reserves and / or 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/or Regulation Service in the Real-Time Market shall be eligible to receive a Bid Production Cost guarantee payment under this Section 18.11.

18.11.2 Formula for Determining BPCG for Demand Side Resources Providing Synchronized Operating Reserves and / or Regulation Service in the Real-Time Market

A Bid Production Cost guarantee payment to a Demand Side Resource with a synchronized Operating Reserves and/or Regulation Service schedule in the real-time Market shall be calculated as follows:

BPCG for Demand Side Resource d Providing synchronized Operating Reserves and/or Regulation Service in Real-Time =

$$max\left(-\sum_{i\in L}\left(NASR_{di}^{TOT} - NASR_{di}^{DA}\right), 0\right)$$

where:

L = set of RTD intervals in the Dispatch Day;

$NASR_{di}^{TOT}$ = Net Ancillary Services 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 interval i which 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 Regulation Capacity and Regulation Movement Bids placed by Demand Side Resource d to provide Regulation Service in that hour at the time it was committed to provide Ancillary Services; and (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.

18.12 Proration Of Start-Up Bid For Generators That Are Committed In The Day-Ahead Market, Or Via Supplemental Resource Evaluation

18.12.1 Eligibility to Recover Operating Costs and Resulting Obligations

Generators committed in the Day-Ahead Market or via SRE that are not able to complete their minimum run time within the Dispatch Day in which they are committed are eligible to include in their Start-Up Bid expected net costs of operating on the day following the dispatch day at the minimum operating level specified for the hour in which the Generator is committed, for the hours necessary to complete the Generator's minimum run time.

Generators that receive Day-Ahead or SRE schedules that are not scheduled to operate in real-time, or that do not operate in real-time, at the MW level included in the Minimum Generation Bid for the first hour of the Generator's Day-Ahead or SRE schedule, for the longer of (a) the duration of the Generator's Day-Ahead or SRE schedule, or (b) the minimum run time specified in the Bid that was accepted for the first hour of the Generator's Day-Ahead or SRE schedule, will have the start-up cost component of the Bid Production Cost guarantee calculation prorated in accordance with the formula specified in Section 18.12.2, below. The rules for prorating the start-up cost component of the Bid Production Cost guarantee calculation apply both to operation within the Dispatch Day and to operation on the day following the Dispatch Day to satisfy the minimum run time specified for the hour in which the Generator was scheduled to start-up on the Dispatch Day.

Rules for calculating the reference level that the NYISO uses to test Start-Up Bids for possible mitigation are included in the Market Power Mitigation Measures that are set forth in Attachment H to the ISO Services Tariff. Proration of the start-up cost component of a Generator's Bid Production Cost guarantee based on the Generator's operation in real-time is different/distinct from the mitigation of a Start-Up Bid.

18.12.2 Proration of Eligible Start-Up Cost when a Generator Is Not Scheduled, or Does Not Operate to Meet the Schedule Specified in the Accepted Day-Ahead or SRE Start-Up Bid.

The start-up costs included in the Bid Production Cost guarantee calculation may be reduced *pro rata* based on a comparison of the actual MWs delivered in real-time to an hourly minimum MW requirement. The hourly MWh requirement is determined based on the MW component of the Minimum Generation Bid submitted for the Generator's accepted start hour (as mitigated, where appropriate).

18.12.2.1 Total Energy Required to be Provided in Order to Avoid Proration of a Generator's Start-Up Costs

$$TotMWReq_{g,s} = MinOpMW_{g,s} * n_{g,s}$$

Where:

$TotMWReq_{g,s}$ = Total amount of Energy that Generator g, when started in hour s, must provide for its start-up costs not to be prorated

$MinOpMW_{g,s}$ = Minimum operating level (in MW) specified by Generator g in its hour s Bid

$n_{g,s}$ = The last hour that Generator g must operate when started in hour s to complete both its minimum run time and its Day-Ahead schedule. The variable $n_{g,s}$ is calculated as follows:

$$n_{g,s} = max\left(LastHrDASched_{g,s}, LastMinRunHr_{g,s}\right)$$

Where:

$LastHrDASched_{g,s}$ = The last date/hour in a contiguous set of hours in the Dispatch Day, beginning with hour s, in which Generator g is scheduled to operate in the Day-Ahead Market

$LastMinRunHr_{g,s}$ = The last date/hour in a contiguous set of hours in which Generator g would need to operate to complete its minimum run time if it starts in hour s

18.12.2.2 Calculation of Prorated Start-Up Cost

$$ProratedSUC_{g,s} = SubmittedSUC_{g,s} * \frac{\sum_{h=s}^{n_{g,s}} MinOpEnergy_{g,h,s}}{TotalMWReq_{g,s}}$$

Where:

$ProratedSUC_{g,s}$ = the prorated start-up cost used to calculate the Bid Production Cost guarantee for Generator g that is scheduled to start in hour s

$SubmittedSUC_{g,s}$= the Start-Up Bid submitted (as mitigated, where appropriate) for Generator g that is scheduled to start in hour s

$MinOpEnergy_{g,h,s}$ = the amount of Energy produced during hour h by Generator g during the time required to complete both its minimum run time and its Day-Ahead schedule, if that generator is started in hour s. $MinOpEnergy_{g,h,s}$ is calculated as follows:

$$MinOpEnergy_{g,h,s} = min(MetActEnergy_{g,h}, MinOpMW_{g,s})$$

Where:

$MetActEnergy_{g,h}$ = the metered amount of Energy produced by Generator g during hour h

18.12.2.3 Additional Rules/Clarifications that Apply to the Calculation of Prorated Start-Up Cost

a. For any hour that a Generator is derated below the minimum operating level specified in its accepted Start-Up Bid for reliability, either by the ISO or at the request of a Transmission Owner, the Generator will receive credit for that hour as if the Generator had produced metered actual MWh equal to its $MinOpMW_{g,s}$.

b. A Generator must be scheduled and operate in real-time to produce Energy consistent with the $MinOpMW_{g,s}$ specified in the accepted Start-Up Bid for each hour that it is expected to run. *See* Section 18.12.2.1, above. These rules do not specify or require any particular bidding construct that must be used to achieve the desired commitment. However, submitting a self-committed Bid may preclude a Generator from receiving a BPCG. *See, e.g.,* Sections 18.2.1.2.2 and 18.4.1.2.3 of this Attachment C.