ATTACHMENT B

I. LBMP CALCULATION METHOD

The Locational Based Marginal Prices ("LBMPs" or "prices") for ~~Generators~~Suppliers and Loads in the Real-Time Market will be based on the system marginal costs produced by either the Real-Time Dispatch ~~Security Constrained Dispatch~~ program, or, during intervals when it is activated, the RTD-CAM program, or, with respect to External Transactions, and during intervals when certain conditions exist at Proxy Generator Buses, the ~~Balancing Market Evaluation~~Real-Time Commitment program. LBMPs for Suppliers and Loads in the Day-Ahead Market will be based on the system marginal costs produced by the ~~, for Real-Time Market prices, or the~~ Security Constrained Unit Commitment ("SCUC") program. ~~for Day-Ahead Market prices.~~

A. ~~Setting~~ Real-Time LBMP Calculation Method

~~The marginal cost of a Fixed Block Unit may set Real-Time LBMP, including intervals in which it forces more economic units to be backed down if it is in economic merit order and is needed to meet Load, displace higher cost Energy or meet Operating Reserve requirements. The marginal cost of a Fixed Block Unit will not set Real-Time LBMP at any other time including those times when it is scheduled solely to meet its minimum runtime requirements or because of other inflexibilities in its operation.~~ **(Note – This paragraph has been moved to Section 4.4.3(B) of Article 4.)**

For each RTD interval, the Pricing Rule that the ISO shall use to calculate LBMPs, the Marginal Losses Component, and the Congestion Component at each Load Zone and Generator bus shall be determined using the table below.

~~These prices are used to settle transactions occurring in the Real-Time Market, with the exception of certain transactions in that market that are settled using prices calculated in BME, as described elsewhere in this Attachment.~~

~~The calculation of LBMPs for Load Zones and Generator buses that are used to settle transactions occurring in the Real-Time Market (with the exception of certain transactions that are settled using prices calculated in BME, as described elsewhere in this Attachment), and of the Marginal Losses Components and Congestion Components of those LBMPs shall be governed by the Pricing Rules described below. For the purposes of this Attachment B, prices calculated pursuant to this Section I.A. will be considered LBMPs determined by SCD.~~

~~For each SCD interval, the Pricing Rule to calculate LBMP, the Marginal Losses Component and the Congestion Component at each Load Zone and Generator bus is indicated in the Table below.~~

		SCR/EDRP NYCA Called and Needed	SCR/EDRP East Called and Needed	Pricing Rule West	Pricing Rule East
~~No NYCA-wide Persistent Ten Minute Reserves Shortage~~	~~No Eastern Persistent Ten Minute Reserves Shortage~~	NO	NO	1	1
			YES	1	2b~~3b~~
		YES	NO	~~3a~~2a	~~3a~~2a
			YES	2a~~3a~~	2a~~3a~~
	~~Eastern Persistent Ten Minute Reserves Shortage~~	~~NO~~	~~NO~~	~~1~~	~~2b~~
			~~YES~~	~~1~~	~~2b~~
		~~YES~~	~~NO~~	~~3a~~	~~2b~~
			~~YES~~	~~3a~~	~~2b~~
~~NYCA-wide Persistent Ten Minute Reserves Shortage~~	~~No Eastern Persistent Ten Minute Reserves Shortage~~	~~NO~~	~~NO~~	~~2a~~	~~2a~~
			~~YES~~	~~2a~~	~~2a~~
		~~YES~~	~~NO~~	~~2a~~	~~2a~~
			~~YES~~	~~2a~~	~~2a~~
	~~Eastern Persistent Ten Minute Reserves Shortage~~	~~NO~~	~~NO~~	~~2a~~	~~2a~~
			~~YES~~	~~2a~~	~~2a~~
		~~YES~~	~~NO~~	~~2a~~	~~2a~~
			~~YES~~	~~2a~~	~~2a~~

Where

SCR/EDRP NYCA, Called and Needed	Is "YES" if the ISO has called SCR/EDRP resources and determined that, but for the Expected Load Reduction, the Available Reserves would have been less than the NYCA requirement for total 30-mMinute rReserves; or is "NO" otherwise.
SCR/EDRP East, Called and Needed	Is "YES" if the ISO has called SCR/EDRP from resources located east of the central east interface and determined that, but for the Expected Load Reduction, the Available Reserves located east of the central east interface would have been less than the requirement for 10-mMinute rReserves located east of the central east interface; or is "NO" otherwise.
Pricing Rule West	Is the pricing rule to use in determining the LBMP, the Congestion Component of LBMP, and the Marginal Losses Component of LBMP for all Generator buses and Load Zones located west of the central east interface, including the Reference Bus.
Pricing Rule East	Is the pricing rule to use in determining the LBMP, the Congestion Component of LBMP, and the Marginal Losses Component of LBMP for all Generator buses and Load Zones located east of the central east interface.

11. Pricing Rule 1.

a. Overview

The ISO shall calculate Real-Time Market LBMPs in the Real-Time Market are calculated pursuant to Pricing Rule 1 shall be using the following three passes of each Real-Time Dispatch run, except as noted below in subsection (1.c). four passes in the Security A new Real-Time Dispatch run will begins every five minutes and each run will produces prices and schedules for five time steps. Only the prices and schedules determined for the first time step of a Real-Time Dispatch run will be binding. Prices and schedules for the other four time steps are advisory only.

Each Real-Time Dispatch run will, depending on the point it which it occurs during the

hour, have a bid optimization horizon of fifty, fifty-five, or sixty minutes- beyond its first time step. The first time step of each Real-Time Dispatch run will be five minutes long. The remaining four time steps of each run can be either five, ten, of fifteen minutes long depending on when the run begins within the hour. The time steps in each RTD run are arranged so that they parallel as closely as possible the quarter hour time steps that are evaluated in RTC.

For example, the run that posts its results at the beginning of an hour ("RTD_0") will initialize at the fifty-fifth minute of the previous hour and produce schedules and prices over a fifty-five minute optimization period. RTD_0 will produce binding prices and schedules for its first five-minute time step, advisory prices and schedules for its second, ten minute time-step, and advisory prices and schedules for its third, fourth and fifth time steps, each of which would span fifteen minutes. The run that posts its results at five minutes after the beginning of the hour ("RTD_5") will initialize at the beginning of the hour and produce prices over a fifty minute optimization period. RTD_5 will produce binding prices and schedules for its first five-minute time step, advisory prices and schedules for it second, five-minute time step, and advisory prices and schedules for its third, fourth and fifth time steps, each of which would span fifteen minutes. The run that posts its results at ten minutes after the beginning of the hour ("RTD_{10}") will initialize at five minutes after the beginning of the hour and produce prices over a sixty minute optimization period. RTD_{10} will produce binding prices and schedules for its first five-minute time step, and advisory prices and schedules for its second, third, fourth and fifth time steps, each of which would span fifteen minutes.

b. Description of the Real-Time Dispatch Passes

(i) The First Pass

The first Real-Time Dispatch pass consists of a least-cost, multi-period co-optimized dispatch for Energy, Regulation and Frequency Response Service and Operating Reserves that treats all Fixed Block Units that are committed by RTC or are otherwise instructed to remain

online by ISO operators as if they were blocked on at their UOL_N or UOL_E, as applicable. The first pass establishes "physical base points" (*i.e.,* real-time Energy schedules) and real-time schedules for Operating Reserves and Regulation and Frequency Response Service for the first time step of the Real-Time Dispatch run. Physical base points and schedules established for the first time step shall be binding and shall remain in effect until the results of the next Real-Time Dispatch run, or an RTD-CAM run, are posted. Physical base points and schedules established for all subsequent time steps shall be advisory. The first pass also produces information that is used to calculate RTD Base Point Signals in the second and third passes.

When establishing physical base points, the first Real-Time Dispatch pass will assume that each Generator will move toward the physical base point established during the first pass of the prior Real-Time Dispatch run at the response rate specified in its Bid.

When setting physical base points for a Dispatchable Resource in the first time step, the first Real-Time Dispatch pass will consider lower and upper dispatch limits for the Resource. These limits shall be based on the feasibility of the Resource reaching the physical base point calculated by the last Real-Time Dispatch or RTD-CAM run given: (A) the metered output level of a Generator -at the time that the Real-Time Dispatch run was initialized; (B) the Resource's response rate; (C) the Resource's minimum generation level; and (D) the Resource's UOL_N or UOL_E, as applicable.

Specifically, if a Resource can, based on its actual output and response rate, reach the physical base point calculated for the first time step of the previous Real-Time Dispatch run then its upper dispatch limit shall equal its previous physical base point plus any possible ramping between the applicable point in time corresponding to the previous physical base point and the point in time corresponding with the first time step of the current Real-Time Dispatch run. Its lower dispatch limit shall equal its previous physical base point less any possible ramping between the applicable point in time corresponding to the previous physical base point and the

point in time corresponding with the first time step of the current Real-Time Dispatch run.

If a Resource cannot, based on its actual output and response rate, reach the physical base point calculated for the first time step of the previous RTD run then its upper and lower dispatch limits are calculated by adding and subtracting any possible ramping from the closest point to the previous physical base point that can be reached by the applicable time of the previous physical base point..

The upper dispatch limit for a Dispatchable Resource that shall be used for the later time steps of the second pass shall be calculated by increasing the upper dispatch limit for the first time step at the Resource's response rate, up to its UOL_N or UOL_E, as applicable. The lower dispatch limit for a Dispatchable Resource that shall be used for the later time steps of the first pass shall be calculated by decreasing the lower dispatch level for the first time step at the Resource's response rate, down to its minimum generation or demand reduction level.

When setting physical base points for a Dispatchable Resource in later time steps, the first Real-Time Dispatch pass will consider: (A) the upper and lower dispatch limits established for the first time step; (B) the Resource's response rate; (C) the Resource's minimum generation or demand reduction level; and (D) the Resource's UOL_N or UOL_E, as applicable.

When setting physical base points for Self-Committed Fixed and ISO-Committed Fixed Generators for all time steps, the first Real-Time Dispatch pass will consider the feasibility of the Generator reaching the output levels that it specified in its self-commitment request for each time point in the Real-Time Dispatch run given: (A) its metered output at the time that the Real-Time Dispatch run was initialized; (B) its response rate.

The RTD Base Point Signals sent to Dispatchable Generators shall be equal to the physical base points calculated in the first Real-Time Dispatch Pass. The RTD Base Point Signals sent to ISO-Committed Fixed and Self-Committed Fixed Generators shall follow the quarter hour operating schedules that those Generators submitted in their real-time self-

commitment requests, regardless of the Generator's actual performance. To the extent possible, RTD Base Point Signals shall honor the response rates specified by the Generators. If a Generator's operating schedule is not feasible based on its real-time self-commitment requests then the RTD Base Point Signals for the Generator will be determined using a response rate consistent with the operating schedule changes.

(ii) The Second Pass

The second Real-Time Dispatch pass consists of a least-cost, multi-period, co-optimized dispatch for Energy, Regulation and Frequency Response Service, and Operating Reserves that treats all Fixed Block Units that are committed by RTC, or that are otherwise instructed to remain online by the ISO, as flexible (they can be dispatched anywhere between zero (0) MW and their UOL_N or UOL_E, as applicable), regardless of their minimum run-time status. The second Real-Time Dispatch pass shall establish "hybrid base points" (*i.e.,* real-time Energy schedules) that are used in the third pass to determine whether minimum run-time constrained Fixed Block Units should be blocked on at their UOL_N or UOL_E, as applicable, or dispatched flexibly as in the second pass. The ISO will not use schedules for Energy, Regulation and Frequency Response Service and Operating Reserves that are established in the second pass to dispatch Resources.

The upper and lower dispatch limits used for ISO-Committed Fixed and Self-Committed Fixed Generators, as well as for Dispatchable Generators that are scheduled to provide Regulation and Frequency Response Service in the first pass, shall be the same as the physical base points calculated in the first pass.

The upper dispatch limit for a Dispatchable Resource that was not scheduled to provide Regulation and Frequency Response Service in the first pass that shall be used in the first time step of the second pass shall be the higher of: (A) the Resource's upper operating limit from the first pass; or (B) the Resource's "pricing base point" for the first time step of the prior RTD

interval (as calculated in the third Real-Time Dispatch pass of that interval) adjusted down within the Resource's Dispatchable range for any possible ramping between the time that the previous pricing base point was issued and the beginning of the current RTD run.

The lower dispatch limit for a Dispatchable Resource that was not scheduled to provide Regulation and Frequency Response Service in the first pass that shall be used in the first time step of the second pass shall be the lower of: (A) the Resource's upper operating limit from the first pass; or (ii) the Resource's "pricing base point" for the first time step of the prior RTD interval (as calculated in the third Real-Time Dispatch pass of that interval) adjusted down within the Resource's Dispatchable range for any possible ramping between the time that the previous pricing base point was issued and the beginning of the current RTD run

The upper dispatch limit for a Dispatchable Resource that was not scheduled to provide Regulation and Frequency Response Service in the first pass that shall be used for the later time steps of the second pass shall be calculated by increasing the upper dispatch limit for the first time step at the Resource's response rate, up to the Resource's UOL_N or UOL_E, as applicable. The lower dispatch limit for a Dispatchable Resource that was not scheduled to provide Regulation and Frequency Response Service in the first pass that shall be used for the later time steps of the second pass shall be calculated by decreasing the lower dispatch level for the first time step at the Resource's response rate, down to the Resource's minimum generation level.

(iii) The Third Pass

The third Real-Time Dispatch pass is the same as the second pass with three variations. First, the third pass treats Fixed Block Units that received a non-zero physical base point in the first pass, and that received a hybrid base point of zero in the second pass, as blocked on at their UOL_N or UOL_E, as applicable. ~~, and all other Dispatchable or otherwise online Fixed Block Units treated as flexible.~~ Second, the third pass produces "pricing base points" (*i.e.,* real-time Energy schedules) instead of hybrid base points. Third, and finally, the third pass calculates real-time

Energy prices and real-time Shadow Prices for Regulation and Frequency Response Service and Operating Reserves that the ISO shall use for settlement purposes pursuant to Article 4, Rate Schedule 3, and Rate Schedule 4 of this ISO Services Tariff respectively. The ISO will not use schedules for Energy, Regulation and Frequency Response Service and Operating Reserves that are established in the third pass to dispatch Resources.

c. Variations in RTD-CAM

When the ISO activates RTD-CAM, the following variation to the rules specified above in subsections 1.a and 1.b above shall apply.

First, if the ISO enters reserve pickup mode: (i) the ISO will solve for a single ten minute time step (not for a multi-step co-optimization period); (ii) the Regulation and Frequency Response Service markets will be temporarily suspended as described in Rate Schedule 3 of this ISO Services Tariff; (iii) ISO operators will have discretion to make additional Generator commitments before executing the three Real-Time Dispatch passes; and (iv) ISO operators will have discretion to allow the RTD Base Point Signal of each Dispatchable Generator to be set to the higher of the Generator's physical base point or it actual generation level.

Second, if the ISO enters maximum generation pickup mode: (i) the ISO will solve for a single five minute time step (not for a multi-step co-optimization period); (ii) the Regulation and Frequency Response Service markets will be temporarily suspended as described in Rate Schedule 3 of this ISO Services Tariff; (iii) ISO operators will have discretion to make additional Generator commitments before executing the three Real-Time Dispatch passes; and (iv) ISO operators will have discretion to either move the market base point of each Generator within the affected area towards its UOL_E at its emergency response rate or set it at a level equal to its physical base point.

Third, if the ISO enters basepoints ASAP – no commitments mode it will solve for a single five minute time step (not for a multi-step co-optimization period).

Fourth, if the ISO enters basepoints ASAP – commit as needed mode: (i) the ISO will solve for a single five minute time step (not for a multi-step co-optimization period); and (ii) the ISO may make additional commitments of Generators that are capable of starting within ten minutes before executing the three Real-Time Dispatch passes.

Fifth, and finally, if the ISO enters re-sequencing mode it will solve for a ten-minute optimization period consisting of two five-minute time steps.

~~Pass 1 consists of a least cost commitment decision ideal dispatch that blocks on all minimum runtime constrained Fixed Block Units at their maximum operating limits. All other Fixed Block Units are assumed to be Dispatchable on a flexible basis (they can be dispatched anywhere between zero (0) MW and their maximum Capacity). This step will determine if it is~~

~~necessary to turn a Fixed Block Unit on or off to provide Energy or Operating Reserves at least cost ("meet Bid Load").~~

~~Pass 2 consists of a least cost dispatch that determines final unit schedules, blocking on, at maximum Capacity all online Fixed Block Units and all Fixed Block Units Selected in the first pass.~~

~~Pass 3 consists of a least cost dispatch that treats all Fixed Block Units as flexible regardless of their minimum runtime status.~~

~~Pass 4 consists of a least cost dispatch that blocks on at maximum Capacity any minimum runtime constrained Fixed Block Units dispatched in Pass 2 that were identified as uneconomic in Pass 3 and calculates prices with all other on-line or Dispatchable Fixed Block Units treated as flexible~~. ~~These prices are used to settle transactions occurring in the Real-Time Market, with the exception of certain transactions in that market that are settled using prices calculated in BME, as described elsewhere in this Attachment.~~

The Marginal Losses Component of the price at each location shall be calculated as the product of the price at the Reference Bus and a quantity equal to the delivery factor produced by ~~SCD~~RTD for that location minus one (1).

The Congestion Component of the price at each location shall be calculated as the price at that location, minus the Marginal Losses Component of the price at that location, minus the price at the Reference Bus.

2.a. Pricing Rule 2a.

(i) Except as noted in Pricing Rule 2a(ii) below:

- The LBMP at the Reference Bus shall be determined by dividing the current Bid Cap by the weighted average of the delivery factors (as defined later in this Attachment) produced by SCD that the ISO uses in its calculation of prices for Zone J in that SCD interval.
- The Marginal Losses Component of the LBMP at each location shall be calculated as the product of the LBMP at the Reference Bus determined above and a quantity equal to the delivery factor produced by SCD for that location minus one.
- The LBMP at each location shall be the sum of the Marginal Losses Component of the LBMP at that location, as determined above, plus the LBMP at the Reference Bus, also as determined above.
- The Congestion Component of the LBMP at each location shall be set to zero.

(ii) However, the ISO shall not use this procedure to set the LBMP for any location lower than the LBMP for that Load Zone or Generator bus calculated pursuant to Pricing Rule 1. In cases in which the procedures described above would cause this rule to be violated:

- The LBMP at each location (including the Reference Bus) shall be set to the greater of the LBMP calculated for that location pursuant to Pricing Rule 1 or the LBMP calculated for that location using the procedure described above in Pricing Rule 2a(i) above.

- The Marginal Losses Component of the LBMP at each location shall be calculated as the product of the LBMP at the Reference Bus and a quantity equal to the delivery factor produced by SCD for that location minus one.
- The Congestion Component of the LBMP at each location shall be calculated as the LBMP at that location, minus the LBMP at the Reference Bus, minus the Marginal Losses Component of the LBMP at that location.

2.b. Pricing Rule 2b.

(i) Except as noted in Pricing Rule 2b(ii) below:

- The Marginal Losses Component of the LBMP at each location shall be calculated as the product of the LBMP at the Reference Bus (which shall be calculated according to either Pricing Rule 1 or Pricing Rule 3a, as determined using the procedures set forth above) and a quantity equal to the delivery factor produced by SCD for that location minus one.
- The Congestion Component of the LBMP at each such location shall be equal to the current Bid Cap, minus the LBMP calculated for the Reference Bus (according to either Pricing Rule 1 or Pricing Rule 3a), minus the Marginal Losses Component of the LBMP for Load Zone J.
- The LBMP at each such location shall be the sum of the LBMP calculated for the Reference Bus (calculated according to either Pricing Rule 1 or Pricing Rule 3a)

~~and the Marginal Losses Component and the Congestion Component for that location.~~

~~(ii) However, the ISO shall not use this procedure to set the LBMP for any location lower than the LBMP for that Load Zone or Generator bus calculated pursuant to Pricing Rule 1. In cases in which the procedures described above would cause this rule to be violated:~~

- ~~The LBMP at each such location shall be set to the LBMP calculated for that location pursuant to Pricing Rule 1.~~
- ~~The Marginal Losses Component of the LBMP at each such location shall be calculated as the product of the LBMP at the Reference Bus (which shall be calculated according to either Pricing Rule 1 or Pricing Rule 3a, as determined using the procedures set forth above) and a quantity equal to the delivery factor produced by SCD for that location minus one.~~
- ~~The Congestion Component of the LBMP at each such location shall be calculated as the LBMP at that location, minus the LBMP calculated for the Reference Bus (according to either Pricing Rule 1 or Pricing Rule 3a), minus the Marginal Losses Component of the LBMP at that location.~~

~~3~~2.~~aa~~. Pricing Rule ~~3~~2a.

(i) Except as noted in ~~Pricing Rule~~subsection ~~3~~2a(ii) below:

- The LBMP at the Reference Bus shall be determined by dividing the lowest offer price at which the quantity of Special Case Resources offered is equal to

$RREQ_{NYCA} – (RACT_{NYCA} – ELR_{NYCA})$, or $500/MWh if the total quantity of Special Case Resources offered is less than $RREQ_{NYCA} – (RACT_{NYCA} – ELR_{NYCA})$, by the weighted average of the delivery factors produced by ~~SCD~~RTD that the ISO uses in its calculation of prices for Load Zone J in that ~~SC~~RTD interval,

where:

- $RACT_{NYCA}$ equals the quantity of Available Reserves in the ~~SCD~~RTD interval;
- $RREQ_{NYCA}$ equals the 30-~~m~~Minute ~~r~~Reserve requirement set by the ISO for the NYCA; and
- ELR_{NYCA} equals the Expected Load Reduction in the NYCA from the Emergency Demand Response Program and Special Case Resources in that ~~SC~~RTD interval.

- The Marginal Losses Component of the LBMP at each location shall be calculated as the product of the LBMP at the Reference Bus and a quantity equal to the delivery factor produced by ~~SC~~RTD for that location minus one.
- The LBMP at each location shall be the sum of the Marginal Losses Component of the LBMP at that location, plus the LBMP at the Reference Bus.
- The Congestion Component of the LBMP at each location shall be set to zero.

(ii) However, the ISO shall not use this procedure to set the LBMP for any location lower than the LBMP for that Load Zone or Generator bus calculated pursuant to Pricing Rule 1. In cases in which the procedures described above would cause this rule to be violated:

- The LBMP at each location (including the Reference Bus) shall be set to the greater of the LBMP calculated for that location pursuant to Pricing Rule 1; or the LBMP calculated for that location using the procedure described above in this Pricing Rule ~~3~~2a(i).
- The Marginal Losses Component of the LBMP at each location shall be calculated as the product of the LBMP at the Reference Bus and a quantity equal to the delivery factor produced by ~~SC~~RTD for that location minus one.
- The Congestion Component of the LBMP at each location shall be calculated as the LBMP at that location, minus the LBMP at the Reference Bus, minus the Marginal Losses Component of the LBMP at that location.

~~3~~2.b. Pricing Rule ~~3~~2b~~.~~

(i) Except as noted in Pricing Rule ~~3~~2b(ii) below:

- The Marginal Losses Component of the LBMP at each location shall be calculated as the product of the LBMP calculated for the Reference Bus (according to Pricing Rule 1) and a quantity equal to the delivery factor produced by ~~SCD~~RTD for that location minus one.
- The Congestion Component of the LBMP at each location shall be equal to the lowest offer price at which the quantity of Special Case Resources offered is equal

to $RREQ_{East} – (RACT_{East} – ELR_{East})$, or $500/MWh if the total quantity of Special Case Resources offered is less than $RREQ_{East} – (RACT_{East} – ELR_{East})$, minus the LBMP calculated for the Reference Bus (according to Pricing Rule 1), minus the Marginal Losses Component of the LBMP for Load Zone J,

where:

- $RACT_{East}$ equals the quantity of Available Reserves located east of the central east interface in that ~~SC~~RTD interval;
- $RREQ_{East}$ equals the 10-~~m~~Minute ~~r~~Reserve requirement set by the ISO for the portion of the NYCA located east of the central east interface; and
- ELR_{East} equals the Expected Load Reduction east of the central east interface from the Emergency Demand Response Program and Special Case Resources in that SCD interval.
- The LBMP at each location shall be the sum of the LBMP calculated for the Reference Bus (according to Pricing Rule 1) and the Marginal Loss Component and the Congestion Component for that location.

(ii) However, the ISO shall not use this procedure to set the LBMP for any location lower than the LBMP for that Load Zone or Generator bus calculated pursuant to Pricing Rule 1. In cases in which the procedures described above would cause this rule to be violated:

- The LBMP at each such location shall be set to the LBMP calculated for that location pursuant to Pricing Rule 1.

- The Marginal Losses Component of the LBMP at each location shall be calculated as the product of the LBMP calculated for the Reference Bus (according to Pricing Rule 1) and a quantity equal to the delivery factor produced by ~~SC~~RTD for that location minus one.
- The Congestion Component of the LBMP at each such location shall be calculated as the LBMP at that location, minus the LBMP calculated for the Reference Bus (according to Pricing Rule 1), minus the Marginal Losses Component of the LBMP at that location.

B. ~~Setting~~ Day-Ahead LBMP Calculation Method

~~The marginal cost of a Fixed Block Unit may set Day-Ahead LBMP, including intervals in which it forces more economic units to be backed down if it is in economic merit order and needed to meet Load, displace higher cost Energy or meet Operating Reserve requirements.~~

(Note: This paragraph has been transplanted to Article 4).

LBMPs in the Day-Ahead Market are calculated using six passes. The first three passes are commitment and dispatch passes, Passes 4, 5 and 6 are dispatch only passes.

Pass 1 consists of a least cost commitment and ideal dispatch to meet Bid Load that assumes that all Fixed Block Units are ~~D~~dispatchable on a “flexible basis” (they can be dispatched anywhere between zero (0) MW and their maximum Capacity).

It consists of several steps. Step 1A is a complete Security Constrained Unit Commitment to meet Bid Load. At the end of this step, Fixed Block Units, Import offers, Export Bids, virtual supply and demand Bids and committed non-Fixed Block Units are dispatched to

meet Bid Load with Fixed Block Units treated as ~~D~~dispatchable on a flexible basis. ~~LBMPs, calculated from this dispatch are used in Step 1B to determine whether In-City mitigation mechanisms will be triggered. If In-City mitigation is triggered, SCUC replaces the offer prices of the affected In-City units with pre-determined reference prices and repeats a complete Security Constrained Unit Commitment to meet Bid Load. At the end of this step, Fixed Block Units, Import offers, Export Bids, virtual supply and demand Bids and committed non-Fixed Block Units are dispatched to meet Bid Load, based, where appropriate, on mitigated offer prices, with Fixed Block Units treated as Dispatchable on a flexible basis~~. LBMPs are calculated from this dispatch. Following Step 1A~~, or 1B if In-City mitigation is triggered,~~ SCUC tests for automated mitigation procedure ("AMP") activation.

If AMP is activated, Step 1B~~C~~ applies the AMP impact test to determine if the AMP will be triggered by mitigating offer prices subject to mitigation that exceed the conduct threshold to their respective reference prices. These mitigated offer prices together with all originally submitted offer prices not subject to automatic mitigation are then used to commit generation and dispatch energy to meet Bid Load. This step is another iteration of the Security Constrained Unit Commitment process. At the end of Step 1B~~C~~, Fixed Block Units, Import offers, Export Bids, virtual supply and demand Bids, and committed non-Fixed Block Units are again dispatched to meet Bid Load using the same mitigated or unmitigated Bids used to determine the commitment to meet Bid Load, with Fixed Block Units treated as ~~D~~dispatchable on a flexible basis. LBMPs are calculated from this dispatch. The LBMPs determined at the end of Step 1B~~C~~ are compared to the LBMPs determined at the end of Step 1A ~~–B~~ to determine the hours and zones in which the impact test is met.

In Step 1C~~D~~, generation offer prices subject to mitigation that exceed the conduct threshold are mitigated for those hours and zones in which the impact test was met in Step 1B~~C~~. The

mitigated offer prices, together with the original unmitigated offer price of units whose offer prices were not subject to mitigation, or did not trigger the conduct or impact thresholds, are used to commit generation and dispatch energy to meet Bid Load. This step is also a complete iteration of the Security Constrained Unit Commitment process. At the end of Step 1CD, Fixed Block Units, Import offers, Export Bids, virtual supply and demand Bids, and committed non-Fixed Block Units are again dispatched to meet Bid Load, with Fixed Block Units treated as Ddispatchable on a flexible basis. LBMPs are calculated from this dispatch.

All non-Fixed Block Units committed in the final step of Pass 1 (which could be either step 1A, 1B, or 1C, or 1D depending on activation of In-City mitigation and the AMP) are blocked on at minimum load in Passes 4 through 6.

Pass 2 consists of a least cost commitment and dispatch of Fixed Block Units, Import offers, Export Bids, and non-Fixed Block Units to meet forecast Load requirements in excess of Bid Load that minimizes the cost of incremental Minimum Generation and Start Up Bids, given revenues for Minimum Generation Energy based on LBMPs calculated in Pass 1, and assumes all Fixed Block Units are dDispatchable on a flexible basis.

Pass 3 consists of a least cost commitment and dispatch of Fixed Block Units, Import offers, Export Bids, and non-Fixed Block Units to meet forecast Load requirements in excess of Bid Load that minimizes the cost of Minimum Generation and Start Up Bids, given revenues for Minimum Generation Energy based on LBMPs calculated in Pass 1 and assumes all Fixed Block Units are Ddispatchable on a flexible basis. Fixed Block Units dispatched in this Pass are not blocked on in Pass 6. Non-Fixed Block Units committed in this step are blocked on at minimum Load in Passes 4 through 6. The difference between Pass 2 and Pass 3 is the inclusion of the In-City reserve and second contingency local reliability criteria. Incremental Import Capacity

needed to meet forecast Load requirements is determined in Pass 3. The costs of satisfying forecast Load and Local Reliability Rules are determined in Pass 3.

Pass 4 consists of a least cost dispatch to forecast Load. It is not used -to set schedules or prices. It is used for operational purposes and provides a dispatch of Fixed Block Units, Import offers, Export Bids and the non-

Fixed Block Units committed in Pass 3 (the "Day-Ahead committed resources") against forecast Loads.

Pass 5 consists of a least cost dispatch of Fixed Block Units, Import offers, Export Bids, virtual supply and demand Bids and Day-Ahead committed resources to meet Bid Load, based where appropriate on offer prices as mitigated in Pass 1. Fixed Block Units are treated as ~~D~~dispatchable on a flexible basis, LBMPs used to settle the Day-Ahead Market are calculated from this dispatch. The Shadow Prices that used to compute Day-Ahead Market Clearing Prices for Regulation and Frequency Response Service and for Operating Reserves in Rate Schedules 3 and 4 of this ISO Services Tariff are also calculated from this dispatch.

Pass 6 consists of a least cost dispatch of Day-Ahead committed resources, Import offers, Export Bids, and virtual supply and demand Bids to meet Bid Load, based where appropriate on offer prices as mitigated in Pass 1, with the schedules of all Fixed Block Units dispatched in the final step of Pass 1 or dispatched above zero in Pass 5 blocked on at maximum Capacity. The schedules of ~~D~~dispatchable units and Imports may be backed down, and Export schedules may be increased, to offset the additional Capacity scheduled on these Fixed Block Units. Final schedules for the Day-Ahead Market are calculated from this dispatch.

C. LBMP Bus Calculation Method

System marginal costs will be utilized in an *ex ante* computation to produce Day-Ahead and ~~r~~Real-~~t~~Time LBMP bus prices using the following equations.

The LBMP at bus 1 can be written as:

$$\gamma_i = \lambda^R + \gamma^L{}_i + \gamma^C{}_i$$

Where:

γ_i	=	LBMP at bus i in $/MWh
λ^R	=	the system marginal price at the Reference Bus
γ_i^L	=	Marginal Losses Component of the LBMP at bus i which is the marginal cost of losses at bus i relative to the Reference Bus
γ_i^C	=	Congestion Component of the LBMP at bus i which is the marginal cost of Congestion at bus i relative to the Reference Bus

The Marginal Losses Component of the LBMP at any bus i within the NYCA is calculated using the equation:

$$\gamma_i^L = (DF_i - 1)\,\lambda^R$$

Where:

DF_i = delivery factor for bus i to the system Reference Bus And:

$$DF_i = \left(1 - \frac{\partial L}{\partial P_i} \right)$$

Where:

L = system losses; and

P_i = ~~generation~~ injection at bus i

The Congestion Component of the LBMP at bus i is calculated using the equation:

$$\gamma_i^c = -\left(\sum_{k \in K}^{n} GF_{ik} \mu_k \right)$$

Where:

K = the set of thermal or Interface Constraints;

GF_{ik} = Shift Factor for ~~the Generator at~~ bus i~~1~~ on Constraint k in the pre- or post-Contingency case which limits flows across that Constraint (the Shift Factor measures the incremental change in flow on Constraint k, expressed in per unit, for an increment of ~~generation~~injection at bus i and a corresponding ~~decrement of generation~~withdrawal at the Reference Bus); and

μ_k = the reduction in system cost that results from an incremental relaxation of Constraint k expressed in $/MWh.

Substituting the equations for γ_i^L and γ_i^C into the first equation yields:

$$\gamma_i = \lambda^R + (DF_i - 1)\lambda^R - \sum_{k \in K} GF_{ik} \mu_k$$

~~The SCD program execution in a given interval may terminate without observing the limits on all Constraints, usually due to Generator ramp rate limitations on the dispatch. Under these conditions, rules have been developed which the ISO will use to set Generator output levels and to calculate LBMPs. These rules state that the LBMPs are to be calculated from the output of the SCD execution in which Constraints were violated. Prices calculated in this manner closely reflect the marginal cost of Energy on the system. However, the Generator output levels will be set by a second SCD execution in which Generator ramp rate Constraints are relaxed. This execution of SCD usually eliminates the Constraint violations and will provide the dispatcher with information to correct the situation. Often Generators will be able to operate at the levels set in the second SCD execution, since they frequently can change their output levels at rates exceeding those included in the Bid data provided to the ISO. Failure to achieve the output levels determined in the second SCD execution will not cause the Generator's performance ratings in the Performance Tracking System to be adversely affected.~~

LBMPs will be calculated for the Day-Ahead and the Real-Time Markets. In the Day-Ahead Market, the three components of the LBMP at each location will be calculated from the SCUC results and posted for each of the 24 hours of the next day. The Real-Time LBMPs will be calculated and posted for each execution of ~~SCD~~RTD.

~~C~~D. Zonal LBMP Calculation Method

The computation described above is at the bus level. ~~This will be suitable for Generator buses because adequate metering is available, or will be provided, to measure Real-Time injections.~~ An eleven (11) zone model will be used for the LBMP billing related to Loads. The LBMP for a zone will be a Load weighted average of the Load bus LBMPs in the zone. The Load weights which will sum to unity will be predetermined by the ISO. Each component of the LBMP for a zone will be calculated as a Load weighted average of the Load bus LBMP components in the zone. The LBMP for a zone *j* can be written as:

$$\gamma_j^Z = \lambda^R + \gamma_j^{L,Z} + \gamma_j^{C,Z}$$

where:

γ_j^Z = LBMP for zone j,

$\gamma_j^{L,Z} = \sum_{i=1}^{n} W_i \gamma_i^L$ is the Marginal Losses Component of the LBMP for zone j;

$\gamma_j^{C,Z} = \sum W_i \gamma_i^C$ is the Congestion Component of the LBMP for zone j;

n = number of Load buses in zone j for which LBMPs are calculated; and

W_i = load weighting factor for bus i.

~~Until the ISO's software can compute LBMPs at Load buses, t~~The zonal LBMPs will be a weighted average of the ~~Generator~~Load bus LBMPs in the zone. The weightings will be pre-determined by the ISO.

~~D~~E. LBMPs ~~Prices~~ for External Locations

1. General Rules

External Generators and Loads can bid into the LBMP Market or participate in Bilateral Transactions. External Generators may arrange Bilateral Transactions with Internal or External Loads and External Loads may arrange Bilateral Transactions with Internal Generators.

The Generator and Load locations for which LBMPs will be calculated will ~~initially~~ be limited to a pre-defined set of buses External to the NYCA. LBMPs will be calculated for each bus within this limited set. ~~LBMPs for any Non-Competitive Proxy Generator Bus shall be calculated as specified below.~~ The three components of LBMP will be calculated from the results of ~~SCD~~RTD, or, in the case of a Proxy Generator Bus, from the results of ~~BME~~RTC_{15} during periods in which (1) proposed economic transactions over the Interface between the NYCA and the Control Area with which that Proxy Generator Bus is associated would exceed the Available Transfer Capability for that Interface, (2) proposed interchange schedule changes pertaining to the NYCA as a whole would exceed any Ramp Capacity limits in place for the NYCA as a whole, or (3) proposed interchange schedule changes pertaining to the Interface between the NYCA and the Control Area with which that Proxy Generator Bus is associated would exceed any Ramp

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Capacity limit imposed by the ISO for that Interface

2. ~~Real-Time LBMPs~~Rules for Non-Competitive Proxy Generator Buses

Real-Time LBMPs for a Non-Competitive Proxy Generator Bus shall be determined as follows.

When (i) proposed Real-Time Market economic net ~~i~~Import transactions into the NYCA from the Control Area in which the Non-Competitive Proxy Generator Bus is located would exceed the Available Transfer Capability for the Interface between the NYCA and the Control Area in which the Non-Competitive Proxy Generator Bus is located, or (ii) proposed interchange schedule changes pertaining to increases in Real-Time Market net imports into the NYCA from the Control Area in which the Non-Competitive Proxy Generator Bus is located would exceed the Ramp Capacity limit imposed by the ISO for the Interface between the NYCA and the Control Area in which the Non-Competitive Proxy Generator Bus is located, the Real-Time LBMP at the Non-Competitive Proxy Generator Bus will be the higher of (i) the ~~BME~~RTC-determined price at that Non-Competitive Proxy Generator Bus or (ii) the lower of the LBMP determined by ~~SCD~~RTD for that Non-Competitive Proxy Generator Bus or zero.

When (i) proposed Real-Time Market economic net export transactions from the NYCA to the Control Area in which the Non-Competitive Proxy Generator Bus is located would exceed the Available Transfer Capability for the Interface between the NYCA and the Control Area in which the Non-Competitive Proxy Generator Bus is located, or (ii) proposed interchange schedule changes pertaining to increases in Real-Time Market net Exports from the NYCA to the Control Area in which the Non-Competitive Proxy Generator Bus is located would exceed the Ramp Capacity limit imposed by the ISO for

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the Interface between the NYCA and the Control Area in which that Non-Competitive Proxy Generator Bus is located, the Real-Time LBMP at the Non-Competitive Proxy Generator Bus will be the lower of (i) the ~~BME~~RTC-determined price at the Non-Competitive Proxy Generator Bus or (ii) the higher of the LBMP determined by ~~SC~~RTD for the Non-Competitive Proxy Generator Bus or the Day-Ahead LBMP determined by SCUC for the Non-Competitive Proxy Generator Bus. ~~At all other times, the Real-Time LBMP shall be calculated as specified in the subsection titled LBMP Prices for External Locations, above.~~

Under the conditions specified below, the Marginal Losses Component and the Congestion Component of the Real-Time LBMP, calculated pursuant to the preceding paragraph, shall be constructed as follows:

When the Real-Time LBMP is set to zero and that zero price was not the result of using the ~~SC~~RTD, ~~BME~~RTC or SCUC-determined LBMP;

Marginal Losses Component of the Real-Time LBMP = Losses $_{\text{~~BME~~RTC PROXY GENERATOR BUS}}$; and

Congestion Component of the Real-Time LBMP = - (Energy $_{\text{~~BME~~RTC REF BUS}}$ + Losses $_{\text{BME PROXY GENERATOR BUS}}$).

When the Real-Time LBMP is set to the Day-Ahead LBMP:

Marginal Losses Component of the Real-Time LBMP = Losses $_{\text{~~BME~~RTC PROXY GENERATOR BUS}}$; and

Congestion Component of the Real-Time LBMP = Day-Ahead LBMP $_{\text{PROXY GENERATOR BUS}}$ - (Energy $_{\text{BME}}$RTC $_{\text{REF BUS}}$ + Losses $_{\text{BME}}$RTC $_{\text{PROXY GENERATOR BUS}}$).

where:

Energy $_{\text{BME}}$RTC $_{\text{REF BUS}}$	=	marginal Bid cost of providing Energy at the reference Bus, as calculated by BMERTC$_{15}$ for the hour;
Losses $_{\text{BME}}$RTC $_{\text{PROXY GENERATOR BUS}}$	=	Marginal Losses Component of the LBMP as calculated by BMERTC$_{15}$ at the Non-Competitive Proxy Generator Bus for the hour; and
Day-Ahead LBMP $_{\text{PROXY GENERATOR BUS}}$	=	Day-Ahead LBMP as calculated by SCUC for the Non-Competitive Proxy Generator Bus for the hour.

The components of LBMP will be posted in the Day-Ahead and Real-Time Markets as described above, except that the Marginal Losses Component of LBMP will be calculated differently for Internal locations. The Marginal Losses Component of the LBMP at each bus, as described above, includes the difference between the marginal cost of losses at that bus and the Reference Bus. If this formulation were employed for an External bus, then the Marginal Losses Component would include the difference in the cost of Marginal Losses for a section of the transmission system External to the NYCA. Since the ISO will not charge for losses incurred Externally, the

formulation will exclude these loss effects. To exclude these External loss effects, the Marginal Losses Component will be calculated from points on the boundary of the NYCA to the Reference Bus.

The Marginal Losses Component of the LBMP at the External bus will be a weighted average of the Marginal Losses Components of the LBMPs at the Interconnection Points. To derive the Marginal Losses Component of the LBMP at an External location, a Transaction will be assumed to be scheduled from the External bus to the Reference Bus. The Shift Factors for this Transaction on the tie lines into these Interconnection buses, which measure the per-unit effect of flows over each of those tie lines that results from the hypothetical transaction, will provide the weights for this calculation. Since all the power from this assumed Transaction crosses the NYCA boundary, the sum of these weights is unity.

The sum of the products of these Shift Factors and the Marginal Losses Component of the LBMP at each of these Interconnection buses yields the Marginal Losses Component of the LBMP that will be used for the External bus. Therefore, the Marginal Losses Component of the LBMP at an External bus E is calculated using the equation:

$$\gamma_E^L = \sum_{b \in I} F_{Eb} (DF_b - 1) \lambda^R$$

where:

γ_E^L = Marginal Losses Component of the LBMP at an External bus E;

F_{Eb} = Shift Factor for the tie line going through bus b, computed for a hypothetical Bilateral Transaction from bus E to the Reference Bus;

$(DF_b - 1)\lambda^R$ = Marginal Losses Component of the LBMP at bus b; and

I = The set of Interconnection buses between the NYCA and adjacent Control Areas.

II. ACCOUNTING FOR TRANSMISSION LOSSES

1.0 Charges

Subject to Attachment K to the ISO OATT, the ISO shall charge all Transmission Customers for transmission system losses based on the marginal cost of losses on either a bus or zonal basis, described below.

1.1 Loss Matrix

The ISO's ~~Security Constrained Dispatch ("SCD")~~ RTD programs ~~will use a loss matrix~~ (referred to as a B matrix) and penalty factors to estimate and model losses in performing generation dispatch and billing functions for losses.

1.2 Residual Loss Payment

The ISO will determine the difference between the payments by Transmission Customers for losses and the payments to Suppliers for losses associated with all

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Transactions (LBMP Market or Transmission Service under Parts II, III and IV of the ISO OATT) for both the Day-Ahead and Real-Time Markets. The accounting for losses at the margin may result in the collection of more revenue than is required to compensate the Generators for the Energy they produced to supply the actual losses in the system. This over collection is termed residual loss payments. The ISO shall calculate residual loss payments revenue on an hourly basis and will credit them against the ISO's Residual Adjustment (See Rate Schedule 1 of the ISO OATT).

2.0 Computation of Residual Loss Payments

2.1 Marginal Losses Component LBMP

The ISO shall utilize the Marginal Losses Component of the LBMP on an Internal bus, an External bus, or a zone basis for computing the marginal contribution of each Transaction to the system losses. The computation of these quantities is described in this Attachment.

2.1.1 Marginal Losses Component Day-Ahead

The ISO shall utilize the Marginal Losses Component computed by the ISO's Security Constrained Unit Commitment ("SCUC") program for computing the marginal contributions of each Transaction in the Day-Ahead Market.

2.1.2 Marginal Losses Component Real -Time

The ISO shall utilize the Marginal Losses Component calculated by the: (i) ~~ISO's SCD~~RTD programs in most cases; (ii) by RTC_{15}, for External Transactions; or, (iii) during intervals when the conditions specified in Part I of this Attachment B exist at Proxy Generator Buses, the ~~BME~~RTC program, for computing the Marginal Losses Component associated with each Transaction scheduled in the Real-Time Market (or deviations from Transactions scheduled in the Day-Ahead Market). The computations will be performed on an ~~SC~~ RTD-interval basis and aggregated to an hourly total.

2.2 Payments and Charges

Payments and charges to reflect the impact of Energy supplied by each Generator, consumed by each Load, or transmitted by each Transmission Customer on the Marginal Losses Component shall be determined as follows. Each of these payments or charges may be negative.

Day-Ahead Payments and Charges

As part of the LBMP paid to all Suppliers scheduled Day-Ahead to provide Energy to the LBMP Market, the ISO shall pay each such Supplier the product of: (a) the injection scheduled Day-Ahead from each of that Supplier's Generators in each hour, in MWh; and (b) the Marginal Losses Component of the Day-Ahead LBMP at each of those Generators' buses, in $/MWh.

As part of the LBMP charged to all LSEs scheduled Day-Ahead to purchase Energy from the LBMP Market, the ISO shall charge each such LSE the product of:~~.~~ (a) the withdrawal scheduled Day-Ahead in each Load Zone by that LSE in each hour, in MWh; and (b) the Marginal Losses Component of the Day-Ahead LBMP in that Load Zone, in $/MWh.

As part of the TUC charged to all Transmission Customers whose Transmission Service has been scheduled Day-Ahead, the ISO shall charge each such Transmission Customer the product of: (a) the amount of Energy scheduled Day-Ahead to be injected and withdrawn by that Transmission Customer in each hour, in MWh; and (b) the Marginal Losses Component of the Day-Ahead LBMP at the Point of Delivery (i.e., Load Zone in which Energy is scheduled to be withdrawn or the bus where Energy is scheduled to be withdrawn if the Energy is scheduled to be withdrawn at a location outside the NYCA), minus the Marginal Losses Component of the Day-Ahead LBMP at the Point of Receipt, in $/MWh.

Real-Time Payments and Charges

As part of the LBMP paid to all Suppliers providing Energy to the Real-Time LBMP Market, ~~in the real-time dispatch~~RTD, ~~the~~ the ISO shall pay each such Supplier the product of: (a) the amount of Energy actually injected by each of that Supplier's Generators in each

hour (to the extent that actual injections do not exceed the AGC or ~~SC~~RTD Base Points Signals sent to that Supplier for those Generators plus any Compensable Overgeneration payable pursuant to ISO ~~p~~Procedures), minus the amount of Energy each of those Generators was scheduled Day-Ahead to inject in that hour, in MWh; and (b) the loss component of the Real-Time LBMP at each of those Generator's buses, in $/MWh.

As part of the LBMP charged to all LSEs that purchase Energy from the LBMP Market, the ISO shall charge each such LSE the product of (a) the Actual Energy Withdrawals by that LSE in each Load Zone in each hour, minus the Energy withdrawal scheduled Day-Ahead in that Load Zone by that LSE for that hour, in MWh; and (b) the Marginal Losses Component of the Real-Time LBMP in that Load Zone, in $MWh.

As part of the TUC charged to all Transmission Customers whose Transmission Service was scheduled after the determination of the Day-Ahead schedule, or who schedule additional Transmission Service after the determination of the Day-Ahead schedule, the ISO shall charge each such Transmission Customer the product of: (a) actual Energy Withdrawals scheduled by RTD in each hour, ~~the amount of Energy scheduled (as of the BME) to be withdrawn by that Transmission Customer in each hour,~~ minus the amount of Energy scheduled Day-Ahead to be withdrawn by that Transmission Customer in that hour, in MWh; and (b) the Marginal Losses Component of the Real-Time LBMP at the Point of Delivery

(i.e., the Load Zone in which Energy is scheduled to be withdrawn or the External bus where Energy is scheduled to be withdrawn if Energy is scheduled to be withdrawn at a location outside the NYCA), minus the Marginal Losses Component of the Real-Time LBMP at the Point of Receipt, in $MWh.

As part of the LBMP paid to all Suppliers generating an amount of Energy that differs from the amount of Energy those Suppliers were scheduled by RTD ~~(as of the BME) t~~o generate in an hour in association with Bilateral Transactions, the ISO shall pay each such Supplier the product of: (a) the amount of Energy actually injected by each of that Supplier's Generators in each hour (to the extent that actual injections do~~.~~ not exceed the AGC or ~~SC~~RTD Base Points Signals sent to that Supplier for those Generators plus any Compensable Overgeneration payable pursuant to ISO ~~p~~Procedures) minus the amount of Energy each of those Generators was scheduled by RTD ~~(as of the BME)~~ to inject in that hour in association with Bilateral Transactions, in MWh; and (b) the Marginal Losses Component of the Real-Time LBMP at each of those Generators' buses, in $/MWh.

As part of the LBMP charged to all LSEs consuming an amount of Energy that deviates from the amount of Energy those LSEs were scheduled by RTD ~~(as of the BME~~RTC) ~~-~~to consume in an hour in association with Bilateral Transactions, the ISO shall charge each such LSE the product of: (a) the Actual Energy Withdrawals by that LSE in each Load Zone in each hour, minus the Energy withdrawal scheduled by RTD ~~(as of the BME)~~ in

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that Load Zone by that LSE for that hour in association with Bilateral Transactions, in MWh; and (b) the Marginal Losses Component of the Real-Time LBMP in that Load Zone, in $/MWh.

III. BILATERAL TRANSACTION BIDDING, SCHEDULING AND CURTAILMENT

1.0 Pre-Scheduled Transaction Requests

Pre-Scheduled Transaction Requests shall include the following information that shall be submitted to the ISO no earlier than eighteen (18) months prior to the Dispatch Day:

1) Point of Injection location;

2) Point of Withdrawal location;

3) Desired Dispatch Days;

4) Hourly MW schedules;

5) Other data as required by the ISO.

Pre-Scheduled Transaction Requests accepted for scheduling may be withdrawn only with the approval of the ISO, pursuant to ISO Procedures.

2.0 Requests for Bilateral Transaction Schedules

Transmission Customers scheduling Transmission Service or to support a Bilateral Transaction with Energy supplied by an External Generator or Internal Generator shall submit the following information to the ISO:

(1) Point of Injection location. For Transactions with Internal sources, the Point of Injection is the LBMP bus; for Transactions with External sources, the Point of Injection is the Proxy Generator Bus; however, based upon such an advance notification to the ISO, an External Supplier will have the additional option of being modeled at a specific External LBMP bus (rather than an External Proxy Generator Bus) and being able to submit a bid curve. Otherwise, an External Supplier with Incremental or Decremental Bids at an External Proxy Generator Bus will be modeled as a single point price curve at that bus. An LBMP bus is a specific bus at

which a Generator Shift Factor has been calculated, and for which LBMP will be calculated.

(2) Point of Withdrawal location. For Internal Load, the Point of Withdrawal is the Load Zone in which the Load is situated or the bus at which that Load is interconnected to the Transmission System, if there is a revenue-quality real-time meter located at that bus (software constraints may initially limit the ability to specify buses as Points of Withdrawal); for delivery points outside the NYCA, the Point of Withdrawal is the Proxy Generator Bus;

(3) Hourly MW schedules;

(4) Minimum run times for Firm Point to Point Transmission Service, if any;

(5) Whether Firm or Non-Firm Transmission Service is requested,

(6) NERC Transaction Priorities for Bilateral Transactions involving External Generators, Exports, and Wheels Through;

(7) A Sink Price Cap Bid for Export transactions up to the MW level of the desired schedule, a Decremental Bid for Import and Wheels Through transactions up to the MW level of the desired schedule provided however that Sink Price Cap Bids and Decremental Bids shall be subject to the following limitations. Day-Ahead Bids for (a) Imports, and Wheels

Through at the Proxy Generator Bus designated as the source of the Transaction, shall be priced no lower than the Bid that provides the highest scheduling priority for sales to the LBMP Market plus the product of (i) the Scheduling Differential and (ii) three; and (b) Exports shall be priced no higher than the Bid that provides the highest scheduling priority for purchases from the LBMP Market minus the product of (i) the Scheduling Differential and (ii) three. Real-Time ~~Market~~ Bids submitted for evaluation in ~~BME~~RTC$_{15}$ for (a) Imports, and Wheels Through at the Proxy Generator Bus designated as the source of the Transaction, shall be priced no lower than the Bid that provides the highest scheduling priority for sales to the LBMP Market plus the product of (i) the Scheduling Differential and (ii) three; and (b) Exports shall be priced no higher than the Bid that provides the highest scheduling priority for purchases to the LBMP Market minus the product of (i) the Scheduling Differential and (ii) three.;

(8) For an Internal Generator, whether the Generator is On-Dispatch or Off-Dispatch;

(9) The amount and location of any Ancillary Services the Transmission Customer will Self-Supply in accordance with and to the extent permitted by each of the Rate Schedules under the ISO OATT; and

(10) Other data required by the ISO.

3.0 Pre-Scheduled Transaction Requests and Bilateral Transaction Scheduling

3.1 ISO's General Responsibilities

Pre-Scheduled Transaction Requests shall be submitted, pursuant to ISO Procedures, no earlier than eighteen (18) months prior to the Dispatch Day, and shall include hourly transaction quantities (in MW) at each affected by External Interface for each specified Dispatch Day. Customers may submit Pre-Scheduled Transaction Requests for scheduling in the Day-Ahead Market.

The ISO shall determine, pursuant to ISO Procedures, the amount of Total Transfer Capability at each External Interface to be made available for scheduling. The ISO shall evaluate Pre-Scheduled Transaction Requests submitted in the order in which they are

submitted for evaluation until the Pre-Scheduled Transaction Request expires, pursuant to ISO Procedures, prior to the close of the Day-Ahead Market for the specified Dispatch Day. Modification of a Pre-Scheduled Transaction request shall constitute a withdrawal of the original request and a submission of a new Pre-Scheduled Transaction Request. At the request of a Customer, the ISO shall continue to evaluate a Pre-Scheduled Transaction Request that was not accepted for scheduling in the priority order in which the Request was originally submitted until it is either accepted for scheduling, is withdrawn or expires, pursuant to ISO Procedures, prior to the close of the Day-Ahead Market for the Specified Dispatch Day. The ISO shall accept Pre-Scheduled Transaction Requests for scheduling, pursuant to ISO Procedures, provided that there is Ramp Capacity, and Transfer Capability available at each affected External Interface, in the NYCA for each hour requested.

If Ramp Capacity or Transfer Capability, on the designated External Interface, is unavailable in the NYCA for any hour of the Pre-Scheduled Transaction Request, the request shall not be scheduled. The ISO shall confirm the Transaction with affected Control Areas, as necessary, pursuant to ISO Procedures and may condition acceptance for scheduling on such confirmation.

The ISO shall provide the requesting Customer with notice, as soon as is practically possible, as to whether the Pre-Scheduled Transaction Request is accepted for scheduling and, if it is not scheduled, the ISO shall provide the reason.

The ISO shall reserve Ramp Capacity, and Transfer Capability on affected Interfaces, for each Pre-Scheduled Transaction. Pre-Scheduled Transactions shall be automatically submitted for scheduling in the appropriate LBMP Market for the designated Dispatch

Day. The ISO shall evaluate requests to withdraw Pre-Scheduled Transactions pursuant to ISO Procedures.

Pre-Scheduled Transactions for Wheels Through in the Day-Ahead Market shall be assigned a Decremental Bid at the Proxy Generator Bus designated as the source of the Transaction that provides the highest scheduling priority available for Firm Transmission Service. The ISO shall evaluate requests for Transmission Service submitted in the Day-Ahead scheduling process using SCUC, and will subsequently establish a Day-Ahead schedule. During the Dispatch Day, the ISO shall use ~~the BME~~ RTC_{15} to establish schedules for each hour of dispatch in that day.

If ~~required by SCD,~~the ISO determines, based on the information provided by RTC, that Curtailments are required ~~the~~ the ISO ~~shall~~ may Curtail Transmission Service during dispatch as described in this Attachment.

3.2 Use of Decremental Bids to Dispatch Internal Generators

When dispatching Generators taking service under the ISO OATT to match changing conditions, the ISO shall treat Decremental Bids and Incremental Bids simultaneously and identically as follows: (i) a generating facility selling Energy in the

LBMP Market may be dispatched downward if the LBMP at the Point of Receipt falls below the generating facility's Incremental Bid; (ii) a Generator serving a Transaction scheduled under the ISO OATT may be dispatched downward if the LBMP at the Generator's Point of Receipt falls below the Decremental Bid for the Generator; (iii) a Supplier's Generator may be dispatched upward if the LBMP at the Generator's Point of

Receipt rises above the Decremental or Incremental Bid for the Generator regardless of whether the Generator is supplying Energy to the LBMP Market or supporting a Transaction scheduled under the ISO OATT.

3.3 Scheduling of Bilateral Transactions

Transmission Service for Bilateral Transactions shall be scheduled as follows:

(i) The ISO shall, following evaluation of the Bids submitted, schedule Transmission Service to support Transactions for the hours in which those Transactions may be accommodated.

(ii) The ISO shall treat all Internal Generators as ~~D~~dispatchable and all External Generators as ~~N~~non-~~D~~dispatchable.

(iii) The ISO will use SCUC and ~~BME~~RTD to determine schedules for Internal Generators and schedules for DNI with other Control Areas so that Firm Transmission Service will be provided to any Bilateral Transaction Customer~~s~~ requesting Firm Transmission Service to the extent that is physically feasible.

(iv) The ISO shall not schedule Non-Firm Transmission Service Day-Ahead for a Transaction if Congestion Rents associated with that Transaction are positive, nor will the ISO schedule Non-Firm Transmission Service in the ~~BME~~ RTC if Congestion Rents associated with that Transaction are expected to be positive. All schedules for Non-Firm Point-to-Point Transmission Service are advisory only and are subject to Reduction if real-time Congestion Rents associated with those Transactions become positive. Transmission Customers receiving Non-Firm Transmission Service will be required to pay Congestion Rents during any delay in the implementation of Reduction (e.g., during the nominal five-minute ~~SC~~RTD intervals that elapse before the implementation of Reduction).

3.4 Day-Ahead Bilateral Transaction Schedules

The ISO shall compute all NYCA Interface Transfer Capabilities prior to

scheduling Transmission Service Day-Ahead. The ISO shall run the SCUC utilizing the computed Transfer Capabilities, submitted Firm Point-to-Point Transmission Service and Network Integration Transmission Service schedules, Load forecasts, and submitted Incremental, Decremental Bids and Sink Price Cap Bids.

In the Day-Ahead schedule, the ISO shall use the SCUC to determine Generator schedules, Transmission Service schedules and DNIs with adjacent Control Areas. The ISO shall not use Decremental Bids submitted by Transmission Customers for Generators associated with Non-Firm Point-to-Point Transmission Service in the determination of the Day-Ahead schedule.

3.5 Reduction and Curtailment

If a Transmission Customer's Firm Point-to-Point Transmission Service or Network Integration Transmission Service is supporting an Internal Bilateral Transaction, or an Import, the ISO shall not Reduce the Transmission Service.

If the Transaction was scheduled in the Day-Ahead Market, and the Day-Ahead Schedule for the Generator designated as the Supplier of Energy for that Bilateral Transaction called for that Generator to produce less Energy than was scheduled Day-Ahead to be consumed in association with that Transaction, the ISO shall supply the Load or Transmission Customer in an Export with Energy from the Day-Ahead LBMP Market.

The Transmission Customer shall continue to pay the Day-Ahead TUC and, in addition, if it takes service under this Tariff, shall pay the Day-Ahead LBMP price, at the Point of Receipt for the Transaction, for the replacement amount of Energy (in MWh) purchased in the LBMP Market. If the Transmission Customer does not take service under this Tariff, it shall pay the greater of 150 percent of the Day-Ahead LBMP at the Point of Receipt for the Transaction or $ 100/MWh for the replacement amount of energy, as specified in the OATT. These procedures shall apply regardless of whether the Generator designated to supply Energy in association with the Transaction was located inside or outside the NYCA.

If the Transaction was scheduled following the Day-Ahead Market, or the schedule for the Transaction was revised following the Day-Ahead Market, then the ISO shall supply the Load or Transmission Customer in an Export with Energy from the Real-Time LBMP Market, at the Real-Time LBMP, if necessary, if (1) the Generator designated to supply the Transaction is an Internal Generator, and it has been dispatched to produce less than the amount of Energy that is scheduled hour-ahead to be consumed in association with that Transaction; or (2) the Generator designated to supply the Transaction is an External Generator, and the amount of Energy it has been scheduled an hour ahead to produce

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(modified for within-hour changes in DNI, if any) is less than the amount of Energy scheduled hour-ahead to be consumed in association with that Transaction; then the Transmission Customer shall pay the Real-Time TUC for the amount of Energy withdrawn in real time in association with that Transaction minus the amount of Energy scheduled Day-Ahead to be withdrawn in association with that Transaction. In addition, to the extent that it has not purchased sufficient replacement Energy in the Day-Ahead Market, the Transmission Customer, if it takes service under this Tariff, shall pay the Real-Time LBMP price, at the Point of Injection for the Transaction, for any additional replacement Energy (in MWh) necessary to serve the Load.

(Revise to Reflect Failed Transactions Rules in Services Tariff. ~~When the Energy injections scheduled by BME at a Proxy Generator Bus are Curtailed for reasons within the control of a Supplier or Transmission Customer, the Supplier or Transmission Customer shall instead pay a charge for the replacement Energy (in MWh) necessary to serve the Load equal to the product of (a) the higher of the time-weighted average of the LBMPs calculated for each SCD interval at the Proxy Generator Bus over the dispatch hour or the price calculated by the BME at the Proxy Generator Bus at which such transaction was scheduled and (b) the scheduled Energy injections minus the actual Energy injections at the Proxy Generator Bus for the dispatch hour.~~

~~When the Energy withdrawals scheduled by BME at a Proxy Generator Bus are Curtailed for reasons within the control of a Supplier or Transmission Customer, the Supplier or Transmission Customer shall be paid the product of: (a) the lower of the time-weighted average of the LBMPs calculated for each SCD interval at the Proxy Generator Bus over the dispatch hour or the price calculated by the BME at the Proxy Generator Bus for that hour and (b) the scheduled Energy withdrawals minus the Actual Energy Withdrawals at that Proxy Bus for the dispatch hour.~~

If the Energy injections scheduled by ~~BME~~RTC$_{15}$ at a Proxy Generator Bus are Curtailed at the request of the ISO then the Supplier or Transmission Customer whose transaction is Curtailed, in addition to paying the charge for replacement Energy necessary to serve the Load and the charge to balance the TUC, as appropriate, shall be paid the product (if positive) of: (a) the Real-Time LBMP at the Proxy Generator Bus minus the higher of the ~~Hour-Ahead Bids~~Real-Time Bid price and zero; and (b) the scheduled Energy injection minus the actual Energy injections at that Proxy Generator Bus for the dispatch hour.

If the Transmission Customer does not take service under this Tariff, it shall pay the greater of 150 percent of the Real-Time LBMP at the Point of Injection for the Transaction or $100/MWh for the replacement amount of Energy, as specified in the OATT. These procedures shall apply regardless of whether the Generator designated to supply Energy in association with that Transaction was located inside or outside the NYCA.

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If the Transmission Customer was receiving Non-Firm Point-to-Point Transmission Service, and its Transmission Service was Reduced or Curtailed, the replacement Energy may be purchased in the Real-Time LBMP Market, at the Real-Time LBMP, by the Internal Load. An Internal Generator supplying Energy for such a Transmission Service that is Reduced or Curtailed may sell its excess Energy in the Real-Time LBMP Market.

The ISO shall not automatically reinstate Non-Firm Point-to-Point Transmission Service that was Reduced or Curtailed. Transmission Customers may submit new schedules to restore the Non-Firm Point-to-Point Transmission Service in the next ~~BME~~ RTC$_{15}$ ~~-~~execution.

If a security violation occurs or is anticipated to occur, the ISO shall attempt to relieve the violation using the following procedures:

(i) Reduce Non-Firm Point-to-Point Transmission Service: Partially or fully physically Curtail External Non-Firm Transmission Service (Imports, Exports and Wheels-Through) by changing DNI schedules to (1) Curtail those in the lowest NERC priority categories first; (2) Curtail within each NERC priority category based on Incremental Bids, Decremental Bids, or Sink Price Cap Bids; and (3) prorate Curtailment of equal cost transactions within a priority category.

(ii) Curtail Non-Firm Point-to-Point Transmission Service: Curtail (through

changing DNI) unscheduled Non-Firm Transactions which contribute to the violation, starting with the lowest NERC priority category.

(iii) Dispatch Internal Generators, based on Incremental and Decremental Bids, including committing additional resources, if necessary;

(iv) Adjust the DNI associated with Transactions supplied by External resources: Curtail External Firm Transactions until the Constraint is relieved by (1) Curtailing based on Incremental Bids, Decremental Bids or Sink Price Cap Bids, and (2) except for External Transactions with minimum run times, prorating Curtailment of equal cost transactions;

(v) Request Internal Generators to voluntarily operate in manual mode below minimum or above maximum ~~D~~dispatchable levels. When operating in manual mode, Generators will not be required to adhere to the one percent minimum ramp rate set forth in Article 4 of the ISO Services Tariff, nor will they be required to respond to ~~SCD~~RTD Base Point Signals;

(vi) In overgeneration conditions, decommit Internal Generators based on ~~m~~Minimum ~~g~~Generation Bid rate in descending order; and

(vii) Invoke other emergency procedures including involuntary Load Curtailment, if necessary.

3.6 Scheduling Transmission Service for External Transactions

The amount of Firm Transmission Service scheduled Day-Ahead for Bilateral Transactions which designate External Generators to supply Imports or Internal Generators to supply Exports will be equal to the amount of Energy scheduled to be consumed under those Transactions Day-Ahead. The amount of Firm Transmission Service scheduled in ~~the BME~~ RTC$_{15}$ for Bilateral Transactions which designate External Generators to supply Imports or Internal Generators to supply Exports will be equal to the amount of Energy scheduled to be consumed under those Transactions in ~~the BME~~ RTC$_{15}$. The DNI between the NYCA and adjoining Control Areas will be adjusted as necessary to reflect the effects of any Curtailments of Import or Export Transactions. Additionally, any Curtailment or Reductions of schedules for Export Transactions will cause the scheduled amount of Transmission Service to change.

The ISO shall use Decremental Bids supplied by Transmission Customers using External Generators to supply Wheels-Through to determine the amount of Energy those Generators are scheduled Day-Ahead to produce in each hour. This in turn will determine the Firm Transmission Service scheduled Day-Ahead to support those

Transactions. The ISO shall also use Decremental Bids supplied by Transmission Customers using External Generators to supply Wheels-Through to determine the amount of Energy these Generators are scheduled to produce in RTC$_{15}$ ~~the BME,~~ which, in turn, will determine the Transmission Service scheduled in ~~the BME~~RTC to support those Transactions.

The amount of Transmission Service scheduled hour-ahead in RTC~~the BME~~ for ~~t~~Transactions supplied by one of the following Generators shall retroactively be set equal to that Generator's actual output in each ~~SC~~RTD interval

(i) Generators providing Energy under contracts executed and effective on or before November 18, 1999 (including PURPA contracts) in which the power purchaser does not control the operation of the supply source but would be responsible for penalties for being off-schedule;

(ii) Existing topping turbine Generators and extraction turbine Generators producing electric Energy resulting from the supply of steam to the district steam system located in New York City (LBMP Zone J) in operation on or before November 18, 1999 and/or topping or extraction turbine Generators utilized in replacing or repowering existing steam supplies from such units (in accordance with good engineering and economic design) that cannot follow schedules, up to a maximum total of 365 MW of such units; and

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

This procedure shall not apply at times when the Generator supplying that ~~t~~Transaction has been scheduled to provide Regulation and Frequency Response Service or Operating Reserves.

The ISO will not schedule a Bilateral Transaction which crosses an Interface between the NYCA and a neighboring Control Area if doing so would cause the DNI to exceed the Transfer Capability of that Interface.

(NOTE – Because there are no further changes, the remainder of Attachment B, which deals with TCCs and TCC Auctions Has Been Deleted from this Draft)

~~IV. SALE OF TRANSMISSION CONGESTION CONTRACTS ("TCCs")~~

~~1.0~~