NEW YORK
INDEPENDENT
SYSTEM OPERATOR

MANUAL 2

Ancillary Services Manual

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Revision History Page

Revision	Date	Changes
3.0	TBD	**Global Changes** All Sections and Attachments include changes to reflect SMD2--Through out the document-All references to SCD changed to RTD, Pool Control Error (PCE) changed to ACE, NYISO changed to NYISO, Security Constrained Dispatch to Real-Time Dispatch. All references to 30- and 10-minute synchronized reserves were changed to 30- and 10-minute spinning reserves. In addition, all references to Transmission Provider (TP) were changed to Transmission Owner (TO). When and where appropriate, RTD was changed to RTD-CAM. **Section 2.3.3** ▪ Reference to Section 2.2.1 instead of repeating the lengthy description **Section 3** ▪ Added ~~“”~~ new text after figure 3.1-1. ▪ Sections 3.4.1 and 3.4.2 ▪ Added “Reinstatement of Payments” **Section 4.2** Changed generating unit operating characteristics exhibit and response rate definitions to reflect Technical Bulletin #71 **Section 4.3.1** ▪ Updated figure 4.3.1-1 **Section 4.3.2** ▪ Added regulation default description. ~~**Section 4.3.4**~~ ~~▪Shortened description with reference to Attachment C and consistency with Technical Bulletin #93~~ **Section 4.3.5** ▪ Added “in proportion to this ramp rate; however, some quantization is needed to avoid very small schedule changes,” to second paragraph. **Section 4.4.1** ▪ Renamed section to Performance Penalty to Performance Adjustment and deleted Deferral of Regulation Performance Penalties **Section 4.4.2 (deleted)** ▪ Old Section 4.4.2 – Regulation Performance Penalty moved to new Attachment D ~~**Section 4.5 & 4.6**~~ ~~▪New replacements and incorporates Technical Bulletins #22 & #53~~ **Section 4.6** ▪ Old Section 4.6 was moved to new Section 4.13 **Section 4.6.4** ▪ Added “In addition, Attachment D of this Manual provides additional information on performance-based adjustments to regulation service payments” to last paragraph. ▪ Moved equation for K_{PI} and additional text to Attachment D. **Section 4.6.5** ▪ Deleted **Section 4.7 – 4.13** ▪ New additions

		Section 6.1 ▪ Joint optimization descriptions added ▪ Deleted text under figure 6.1-1. **Sections 6.2 – 6.10** ▪ Replaces old Sections 6.2 – 6.4 **Section 6.2** ▪ Inserted new section and table to be consistent with Technical Bulletin #87~~This new section is consistent with Technical Bulletins #50, #87, & #97~~ ~~**Section 6.6 & 6.7**~~ ▪ ~~These new sections incorporate Technical Bulletin #54~~ **Section 6.7.2** ▪ Added the following paragraph "Scarcity pricing rules A and B are invoked when SCR/EDRP resources are activated and, but for the SCR/EDRP resources, the NYCA would experience a shortage of reserve. Scarcity pricing rule A applies when, but for SCR/EDRP resources, the NYCA would experience a shortage of reserve. Scarcity pricing rule B applies when, but for SCR/EDRP resources, the eastern portion of the NYCA would experience a shortage of reserve." ~~**Section 6.8**~~ ▪ ~~This new section is consistent with Technical Bulletin #93~~ **Section 6.11** Same as old Section 6.5 **Section 6.12** ▪ Same as old Section 6.6 **ATTACHMENTS** Deleted original Attachment A- Dispatch Load & Spinning Reserve—The remaining attachments were re-numbered **Attachment A** ▪ New test forms **Attachment B-AGC Functional Requirements** ▪ Under section "Unit Response Rates" ▪ First paragraph added "A unit may specify up to three NORMAL response rates. When multiple NORMAL response rates are defined, each is applied to a portion of the unit's operating range." ▪ Second paragraph-added "the capacity-weighted" before the three instances of NRR. In addition, made NRR plural. ▪ End of Ramped RTD Basepoints section, added text from section 5.3.7 of the Transmission and Dispatching Ops Manual. **Replaced Attachment C** ▪ Regulation Performance Penalty with Regulation Performance Adjustment. ▪ Added equation for K_{PI} and additional text from section 4.6.4 to Attachment C. **Attachment E** ▪ Performance Standards Overview-Added link to NERC site, which replaces the old Attachment D detailed description. **Deleted Attachment F**
2.0	**4/6/04**	*Complete reformatting of document. - All sections, grammar and syntax corrections. **Section 3.3.1 – 3.3.3** **Section 3.5.1, 3.5.2** ▪ ~~o~~ Deleted references to Six-year testing, and updated the cost determination to reflect current NYISO Market Services Tariff/Rate Schedule No. 2.

		Section 4.1 ▪ ~~o~~ Added "which may vary by hour and by season. Seasonally, the NYISO shall post the hourly regulation and frequency response requirements and, prior to the start of the season, shall present the regulation and frequency response requirements to the SOAS for discussion and comment. Should the NYISO determine that it intends to establish regulation and frequency response requirements for any hour that are lower than any requirement for that hour in the seasonal regulation and frequency response requirements published as of March 1, 2004, it shall present, prior to posting, its analysis and the revised requirement to the Operating Committee for approval. Should the NYISO determine, for reliability reasons, that it intends to establish regulation and frequency response requirements for any hour that are higher than the requirement for that hour currently in effect, it shall raise the requirement, issue a notice as soon as possible, repost the hourly regulation and frequency response requirements for that season, and discuss its adjusted regulation and frequency response requirement for that hour at the next regularly scheduled Operating Committee meeting. Shortly after the end of each Capability Period, the NYISO shall present SOAS with an analyses of the regulation performance in that Capability Period." to second paragraph. **Section 4.3** ▪ ~~o~~ Added "As specified in Section 4.1, r" to first sentence. Added "or directly from the NYISO." to last sentence. **Section 4.3.2** ▪ ~~o~~ Added "for that day" to first sentence. **Attachment B** ▪ Replaced Reactive Capability test form with current (2004) version.
1.0	**7/15/99**	**Initial Release** **Section 2.3.2, page 8** ▪ ~~o clarification~~ Clarification of applicability of service charges **Section 2.3.3, page 10** ▪ ~~o~~ Charges Associated with Local Reliability Rules **Section 3.3.5, page 7** ▪ ~~o clarification~~ Clarification of applicability of voltage support charges

1. OVERVIEW

This section gives an overall description of the following Ancillary Services.

- Scheduling, System Control & Dispatch Service
- Voltage Support Service
- Regulation & Frequency Response Service
- Energy Imbalance Service
- Operating Reserve Service
- Black Start Capability Service

1.1 Purpose

The purpose of this Manual is to provide an overview of the Ancillary Services available in the New York market along with settlement process associated with each of the available ancillary services.

1.2 Summary of Services

Definition of Ancillary Services

Ancillary Services support the transmission of energy from resources to loads, while maintaining reliable operation of the New York State (NYS) Power System. Ancillary Services consist of physical equipment and human resources. The New York Independent System Operator (NYISO) is also responsible for directing the actions of Generation Resources and other facilities that provide Ancillary Services to the NYISO.

The NYISO coordinates the provision of all Ancillary Services and directly arranges for the supply of all Ancillary Services that are not self-supplied. Some Ancillary Services must be provided by the NYISO; others ~~can~~ can either be provided by ~~either~~ the NYISO or procured by the Transmission Customers and Suppliers themselves. Some Ancillary Services are provided at market-based prices~~;~~ , while others, due to the nature of the service, are provided at embedded cost-based prices. All Ancillary Service providers must be scheduled by the NYISO. Table 1.1 presents a summary of the NYISO Ancillary Services.

Table 1.1: Ancillary Services Summary

Ancillary Services	Is the Service Location Dependent?	Who provides the Service – NYISO or Self-Supplied (SS)?	What is the Pricing method for the Ancillary Service?
Scheduling, System Control and Dispatch Service	No	NYISO	Embedded
Voltage Support Service	Yes	NYISO	Embedded
Regulation and Frequency Response Service	Yes	NYISO or (SS)	Market-based
Energy Imbalance Service	No	NYISO	Market-based
Operating Reserve Service	Yes	NYISO or (SS)	Market-based
Black Start Capability Service	Yes	NYISO	Embedded

1.3 Self-Supply of Ancillary Services

Transmission Customers and Suppliers are permitted to Self-Supply certain Ancillary Services, as identified in Table 1.1. In general, the following process must occur in order to Self-Supply Ancillary Services:

1. A Transmission Customer bids the resource required to provide the Ancillary Service into the Ancillary Services market.

2. The NYISO selects the successful bidders to provide each Ancillary Service~~.~~ . The selection of all Ancillary Service providers is subject to the same locational criteria.

3. Transmission Customers and Suppliers with resources selected by the NYISO use the revenues that they would otherwise have received for providing these services as an offset against charges they would otherwise need to pay the NYISO for the service.

   - The LSEs identify in their application to NYISO the Ancillary Services that they plan to purchase through the NYISO.
   - All suppliers of Ancillary Services using the self-supply option must place the facility under the operational control of the NYISO. All of these resources are subject to the same NYISO locational and performance criteria, and are subject to all payments and penalties as are defined for all other suppliers of the service.
   - For more information, see the ***NYISO Accounting and Billing Manual***.

1.4 Metering Requirements

- Ancillary Services Suppliers must ensure that adequate metering data is made available to the NYISO by direct transmission to the NYISO through existing Transmission Owner communication equipment.
- Additionally, for operational purposes, metered data provided to the NYISO must also simultaneously be provided to the ~~Transmission Provider~~Transmission Owner, which will handle such information consistent with the *OASIS* standards of conduct as specified in FERC Order No. 889.

~~Ancillary Services Suppliers must ensure that adequate metering data is made available to the NYISO by the following means:~~
~~– direct transmission to the NYISO through existing Transmission Owner communication equipment~~
~~Additionally, for operational purposes, metered data provided to the NYISO must also simultaneously be provided to the Transmission Provider which will handle such information consistent with the **OASIS** standards of conduct as specified in FERC Order No. 889~~.

2. SCHEDULING, SYSTEM CONTROL & DISPATCH SERVICE

This section describes the scheduling, system control and dispatch services provided by the New York Independent System Operator (NYISO).

2.1 Description

The scheduling, system control and dispatch service is grouped into two broad categories related to the physical operation of the NY Control Area:

- System Security Management in real-time
- Capacity Management

The list of services, together with a description of each service~~,~~ is presented in Tables 2.1-1 and 2.1-2.

Table 2.1-1: System Security Management in Real Time Functions

Service Function	Description
Tie-Line Regulation & Frequency Support	The NYISO develops the Area Control Error (ACE) for the NY Control Area and Automatic Generation Control (AGC).
System Restoration	The NYISO develops and manages operating procedures to be used as a guide to NY Control Area restoration, following major disturbances. The NYISO provides restoration training to NYISO Dispatchers, Transmission Owners, LSEs, and Generators.
Time Error Management	The NYISO performs all required activities for time error correction and coordinates this activity with neighboring Control Areas.
Interchange Scheduling Management	The NYISO coordinates the scheduling of all Bilateral Transactions in the Day-Ahead ~~and Hour-Ahead~~and Real-Time Market. The NYISO prepares a monthly forecast, on a daily basis, of all system transfer limitations due to scheduled facility outages.
System Emergency Management	The NYISO develops procedures for operation of the New York Control Area that define the various security operating states and the responsibilities of the NYISO and the LSEs. System emergency management entails the cooperation of the NYISO, LSEs, ~~Transmission Provider~~Transmission Owners, and Generators in returning the NY Control Area to a Normal State from either a Major Emergency, Warning, or Alert State.
Administration of Inter-Control Area Emergency Transactions	The NYISO coordinates the purchases and sales of Energy and Capacity, on a prescheduled or emergency basis, to prevent the NY Control Area from leaving the Normal State or to assist neighboring Control Areas.
Operator Initiated Load Shedding	The NYISO develops and manages operating procedures that specify conditions under which NYISO directed Load Shedding is carried out.
Under Frequency Load Shedding	The NYISO establishes guidelines and coordinates the settings and amounts of automatic under~~-~~frequency Load Shedding that is executed by under~~-~~frequency relays within each Transmission ~~Owner's~~ Owners' distribution area.
Transmission System Operation	The NYISO monitors the operation of the transmission system and coordinates circuit, capacitor, and inductor switching, as well as scheduling flows on phase angle regulators (PARs) which control the flows into or out of neighboring control areas.

Service Function	Description
~~Security Constrained Dispatch~~Real-Time Commitment (RTC) and Real-Time Dispatch (~~SCD~~RT~~C~~D) Programs	The NYISO maintains and modifies the RTC and ~~SCD~~RTD programs, as required, to maintain reliable power system operation.
Security Constrained Unit Commitment (SCUC) Programs	The NYISO maintains and modifies the SCUC programs, as required, to maintain reliable power system operation.
Locational-Based Marginal Price Programs	The NYISO maintains and modifies the LBMP software programs as required.
Communications	The NYISO PCC and ~~Transmission Provider~~Transmission Owner Control Centers maintain communication systems and SCADA systems. The NYISO also maintains an OASIS node and an Electronic Bid System.

Table 2.1-2: Capacity Management Functions

Service Function	Description
Installed Capacity Criteria & Requirements	The NYISO establishes the installed capacity requirements for each LSE, based on standards promulgated by the NYSRC.
On-Line & Forecasted Capacity Management	The NYISO, on a Day-Ahead and week-ahead basis, forecasts the expected operating capacity that is required to meet the forecasted peak load and reserve requirement.
Operating Reserve Management	The NYISO continuously monitors the Operating Reserve to ensure that there is sufficient on-line capacity to meet the peak load and reserve requirements of the dispatch day.
Operating Reserve Scheduling	The NYISO establishes operating procedures for the management of Operating Reserve. The NYISO establishes the required amount of Operating Reserve and schedules the bidding suppliers to provide the service.
Generator Outage Scheduling	The NYISO coordinates the generator maintenance schedules to ensure sufficient Operating Reserve margins.
Transmission Facility Outage Coordination	The NYISO coordinates all requests transmission outages to ensure system reliability and transmission transfer capabilities.
Generation and Auxiliary~~Ancillary~~ Facility Outage Coordination	The NYISO coordinates the simultaneous outages of generators and key auxiliary generator equipment such as Automatic Voltage Regulators (AVRs) and Power System Stabilizers (PSSs), in order to maintain the security of the NY Control Area.

2.2 Recovery of NYISO Costs

This section describes how NYISO's costs are recovered.

2.2.1 Costs Recovered Through NYISO Open Access Transmission Tariff

New York Independent System Operator (NYISO) costs to be recovered through the Rate Schedule 1 charge of the ~~ISO~~ NYISO OATT include:

Costs associated with the operation of the NYS Transmission System by the ~~ISO~~ NYISO and administration of this Tariff by the NYISO, including without limitation, the following:

Processing and implementing requests for transmission service including support of the NYISO OASIS node~~;~~:

- Coordination of transmission system operation and implementation of necessary control actions by the NYISO and support for these functions;
- Performing centralized ~~security constrained dispatch~~real-time dispatch to optimally redispatch the NYS Power System to mitigate transmission Interface overloads and provide balancing services;
- Billing associated with Transmission Service provided under this Tariff;
- Preparation of Settlement statements;
- Rebilling which supports this service;
- NYS Transmission System studies, when the costs of the studies are not recoverable from a Transmission Customer;
- Engineering services and operations planning;
- Data and voice communications network service coordination;
- Metering maintenance and calibration scheduling;
- Dispute resolution
- Record keeping and auditing;
- Training of NYISO personnel;
- Development of new information, communication and control systems;
- Professional services;
- Carrying costs on NYISO assets, capital requirements and debts;
- Tax expenses, if any;
- Administrative and general expenses;
- Insurance expenses;
- Costs ~~that~~ the NYISO incurs as a result of bad debt, including finance charges;

- The costs associated with differences between the amounts bid by generating facilities that have been committed and scheduled by the ~~ISO~~ NYISO to provide Energy and certain Ancillary Services, and the actual revenues received by these generating facilities for providing such Energy and Ancillary Services. Where the costs are incurred to compensate generating facilities for satisfying Local Reliability Rules, the associated charge shall apply only to Transmission Customers serving Load in the Load Zone(s) where the rule is applied.
  - Amortized costs associated with the start-up and formation of the ISO, including without limitation, the following:
    - the transfer of any property, including real, personal, and intellectual property, other assets, and other rights and obligations;
    - items such as computer software development and licensing costs and computer hardware costs; and
    - costs related to regulatory filings.

These costs will be amortized over a ten-year period, and the amortized charge will include financing costs.

Subject to the above, where costs, ~~or~~ expenses, or receipts are incurred on a basis other than a monthly basis, the ~~ISO~~ NYISO shall use reasonable judgment consistent with commonly accepted accounting practices to develop the monthly components. The sum of the costs identified above shall be adjusted by all ancillary service penalties collected by the ~~ISO~~ NYISO and by the Residual Adjustment.

Residual Adjustment

a) Open Access Transmission Tariff

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

The greater revenue the NYISO collects for Marginal Losses from Transmission Customers, in contrast to payments for losses remitted to generation facilities;

- Costs or savings associated with the ~~ISO~~ NYISO redispatch of Generators resulting from a change in Transfer Capability between the Day-Ahead schedule and the real-time dispatch;
- The cost resulting from inadvertent interchange (if unscheduled Energy flows out of the NYCA to other Control Areas), or the decrease in cost resulting from inadvertent interchange (if unscheduled Energy flows into the NYCA from other Control Areas) and associated payments in kind;
- Costs or revenues from Emergency Transactions with other Control Area operators;
- Metering errors resulting in payments to or from Transmission Customers to be either higher or lower than they would have been in the absence of metering errors;

- Deviation between actual system Load and the five-minute ahead Load forecast used by ~~SCD~~RTD, resulting in either more or less Energy than is needed to meet Load;
- Energy provided by generation facilities in excess of the amounts requested by the ~~ISO~~ NYISO (through ~~SCD~~ RTD Basepoint Signals or AGC Basepoint Signals);

- ~~If generation facilities providing Regulation Service have actual output in excess of their AGC Basepoint Signals, but the SCD Basepoint Signals is higher than either, the real-time payments they receive for Energy produced will be based on the SCD Basepoint Signals; and~~

- Transmission Customers serving Load in the NYCA will be billed based upon an estimated distribution of Loads to buses within each Load Zone. If the actual distribution of Load differs from this assumed distribution, the total amount collected from Transmission Customers could be either higher or lower than the amount that would have been collected if the actual distribution of Loads had been known.
- Settlements for losses revenue variances, as described in Attachment K of this Tariff, with Transmission Owners that pay marginal losses to the ~~ISO~~ NYISO for losses associated with modified TWAs (not converted to TCCs) while receiving losses payments from the participants in those TWAs other than marginal losses.

The actual Residual Adjustment for each month shall be the sum of the hourly Residual Adjustments calculated as follows: (A) the ISO's receipts from Transmission Customers and Primary Holders of TCCs for services which equal the sum of (i) payments for Energy scheduled in the LBMP Market in that hour in the Day-Ahead commitment; (ii) payments for Energy purchased in the real-time LBMP Market for that hour that was not scheduled Day-Ahead; (iii) payments for Energy by generating facilities that generated less Energy in the real-time dispatch for that hour than they were scheduled Day-Ahead to generate in that hour for the LBMP Market; (iv) TUC payments made in accordance with Parts II, III and IV of this Tariff that were scheduled in that hour in the Day-Ahead commitment; and (v) real-time TUC payments in accordance with Parts II, III and IV of this Tariff that were not scheduled in that hour in the Day-Ahead commitment; (B) less the ISO's payments to generation facilities, Transmission Owners and Primary Holders of TCCs equal to the sum of the following: (i) payments for Energy to generation facilities that were scheduled to operate in the LBMP Market in that hour in the Day-Ahead commitment; (ii) payments to generation facilities for Energy provided to the ~~ISO~~ NYISO in the real-time dispatch for that hour that those generation facilities were not scheduled to generate in that hour in the Day-Ahead commitment; (iii) payments for Energy to LSEs that consumed less Energy in the real-time dispatch than those LSEs were scheduled Day-Ahead to consume in that hour; (iv) payments of the real-time TUC to Transmission Customers that reduced their schedules for that hour after the Day-Ahead commitment; (v) payments of Congestion Rents collected for that hour in the Day-Ahead schedule to Primary Holders of TCCs; (vi) settlements with

Transmission Owners for losses revenue variances; and (vii) Excess Congestion Rents collected in that hour.

2.2.2 Costs Recovered Through NYISO Services Tariff

New York Independent System Operator ~~(ISO)~~ costs to be recovered through the Rate Schedule 1 charge of the ~~ISO~~NYISO Services Tariff shall include costs incurred by the ~~ISO~~NYISO that are directly assignable to the services provided by the ~~ISO~~NYISO under the Tariff and are not recoverable under Rate Schedule 1 of the ~~ISO~~NYISO Open Access Transmission Tariff (OATT). Costs recoverable under this charge shall include costs related to: the ~~ISO~~NYISO's administration of the Locational Based Marginal Pricing (LBMP) Markets; the ~~ISO~~NYISO's administration of Installed Capacity requirements and an Installed Capacity Market; the ~~ISO~~NYISO's administration of Control Area Services, other than Ancillary Services provided under the ~~ISO~~NYISO OATT; the ~~ISO~~NYISO's administration of the Market Power Monitoring Program; and other activities related to the maintenance of reliability in the New York Control Area (NYCA). These costs shall be offset by installed capacity deficiency penalties collected by the ~~ISO~~NYISO.

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

2.3 Payment for Service

The NYISO charges and Transmission Customers pay the Scheduling, System ~~Control~~Control, and Dispatch Service charge on all Transmission Services provided pursuant to the NYISO Tariff, including Bilateral Transactions within the NYCA, purchases of Energy from the LBMP Market, Wheels Through, and Exports.

For more information, see the ***NYISO ~~Manual for~~ Accounting & Billing Manual***.

2.3.1 Computation of Rate

The Scheduling, System ~~Control~~Control, and Dispatch Service charge rate for both the ~~ISO~~NYISO OATT and the ~~ISO~~NYISO Services Tariff are computed on a monthly basis based on information available from the prior month. Each charge rate is equal to the quotient of the NYISO's monthly costs and expenses allocated to that tariff, as discussed in the preceding section, divided by the total number of billing units that apply to that tariff.

~~ISO~~NYISO Billing Units

For the purposes of the ~~ISO~~NYISO OATT, the billing units for each customer shall consist of the actual energy withdrawals for that month to supply load in the NYCA, and hourly energy schedules for all wheel-through and export transactions. The total billing units will be equal to the sum of the billing units for all customers taking service under the OATT.

~~ISO~~NYISO Services Tariff Billing Units

For the purposes of the ~~ISO~~NYISO Services Tariff, the billing units for each customer shall consist of the actual energy withdrawals for that month to supply load in the NYCA, and all other purchases from LBMP markets to supply load outside the NYCA. The total billing units will be equal to the sum of the billing units for all customers taking service under the ~~ISO~~NYISO Services Tariff.

2.3.2 Billing

The amount the NYISO charges each Transmission Customer under both the ~~ISO~~NYISO OATT and the ~~ISO~~NYISO Services Tariff are calculated as follows:

NYISO Charge = NYISO Service Charge Rate for the Appropriate Tariff * Monthly Billing Units for the Appropriate Tariff

Note: In cases where a Transmission Customer is a retail access customer served by an LSE, the LSEs shall be responsible for paying this charge to the ~~ISO~~NYISO.

The billing units will be based on the number of MWH withdrawn in each month from the NYCA, to supply load inside or outside the NYCA. In addition, Transmission Customers not taking service under the ~~ISO~~NYISO Services Tariff will not be assessed its Rate Schedule 1 charge.

2.3.3 Charges Associated with Local Reliability Rules

In addition to the above charges, Transmission Customers taking service under the ~~ISO~~NYISO OATT may be assessed additional Schedule 1 charges associated with local reliability rules. These charges shall be allocated among the customers in the affected areas based on the actual energy withdrawals in the subzones when the local reliability rules were applied. In cases where a Transmission Customer is a retail access customer served by an LSE, the LSE shall be responsible for paying these charges.

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

- The greater revenue the ISO collects for Marginal Losses from Transmission Customers, in contrast to payments for losses remitted to generation facilities;
- Costs or savings associated with the ISO redispatch of Generators resulting from a change in Transfer Capability between the Day-Ahead schedule and the real-time dispatch;
- The cost resulting from inadvertent interchange (if unscheduled Energy flows out of the NYCA to other Control Areas), or the decrease in cost resulting from inadvertent interchange (if unscheduled Energy flows into the NYCA from other Control Areas) and associated payments in kind;
- Costs or revenues from Emergency Transactions with other Control Area operators;

- Metering errors resulting in payments to or from Transmission Customers to be either higher or lower than they would have been in the absence of metering errors;
- Deviation between actual system Load and the five-minute ahead Load forecast used by SCD, resulting in either more or less Energy than is needed to meet Load;
- Energy provided by generation facilities in excess of the amounts requested by the ISO (through SCD Basepoint Signals or AGC Basepoint Signals);
- If generation facilities providing Regulation Service have actual output in excess of their AGC Basepoint Signals, but the SCD Basepoint Signals is higher than either, the real-time payments they receive for Energy produced will be based on the SCD Basepoint Signals; and
- Transmission Customers serving Load in the NYCA will be billed based upon an estimated distribution of Loads to buses within each Load Zone. If the actual distribution of Load differs from this assumed distribution, the total amount collected from Transmission Customers could be either higher or lower than the amount that would have been collected if the actual distribution of Loads had been known. These charges will be calculated and posted monthly.
- Settlements for losses revenue variances, as described in Attachment K of this Tariff, with Transmission Owners that pay marginal losses to the ISO for losses associated with modified TWAs (not converted to TCCs) while receiving losses payments from the participants in those TWAs other than marginal losses.

~~The actual Residual Adjustment for each month shall be the sum of the hourly Residual Adjustments calculated as follows: (A) the ISO's receipts from Transmission Customers and Primary Holders of TCCs for services which equal the sum of (i) payments for Energy scheduled in the LBMP Market in that hour in the Day-Ahead commitment; (ii) payments for Energy purchased in the real-time LBMP Market for that hour that was not scheduled Day-Ahead; (iii) payments for Energy by generating facilities that generated less Energy in the real-time dispatch for that hour than they were scheduled Day-Ahead to generate in that hour for the LBMP Market; (iv) TUC payments made in accordance with Parts II, III and IV of this Tariff that were scheduled in that hour in the Day-Ahead commitment; and (v) real-time TUC payments in accordance with Parts II, III and IV of this Tariff that were not scheduled in that hour in the Day-Ahead commitment; (B) less the ISO's payments to generation facilities, Transmission Owners and Primary Holders of TCCs equal to the sum of the following: (i) payments for Energy to generation facilities that were scheduled to operate in the LBMP Market in that hour in the Day-Ahead commitment; (ii) payments to generation facilities for Energy provided to the ISO in the real-time dispatch for that hour that those generation facilities were not scheduled to generate in that hour in the Day-Ahead commitment; (iii) payments for Energy to LSEs that consumed less Energy in the real-time dispatch than those LSEs were scheduled Day-Ahead to consume in that hour; (iv) payments of the real-time TUC to Transmission Customers that reduced their schedules for that hour after the Day-Ahead commitment; (v) payments of Congestion Rents collected for that hour in the Day-Ahead schedule to Primary Holders of TCCs; (vi) settlements with Transmission Owners for losses revenue variances; and (vii) Excess Congestion Rents collected in that hour.~~

~~2.4.~~2.4 Services Performed at the Request of a Market Participant

Market Participants may request and pay for the following NYISO Services:

- ~~2.5~~ System Reliability Impact Study (ESRIS)
- Facilities Study
- Local Control Center operator training
- Re-enforcement Option Study (PSC can also request)
- System Impact Study
- Interconnection Study

Studies may also be requested by the New York State Reliability Council (NYSRC). For further details, see the ***Transmission Expansion and Interconnection Manual***.

3. VOLTAGE SUPPORT SERVICE

This section describes the voltage support service (VSS).

~~3.1.~~3.1 Description

In order to maintain transmission voltages on the NYS Transmission System within acceptable limits, generation facilities under the control of the ~~ISO~~NYISO are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control Service ("Voltage Support Service") must be provided to support all Transactions on the NYS Transmission System. The amount of ~~Voltage Support Service~~VSS that must be supplied will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by the ~~ISO~~NYISO.~~, as shown in Figure 3.1-1.~~

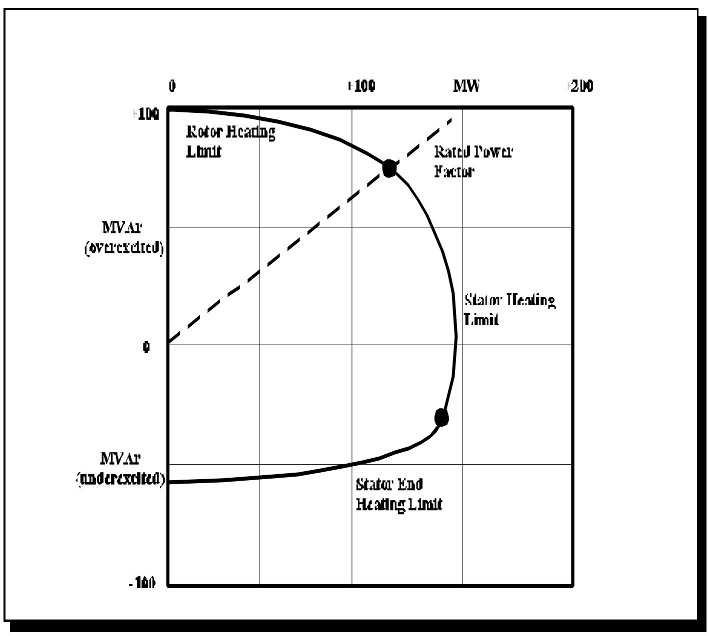


Figure 3.1: Generator MVAr versus MW Capability

~~**Note to Reader**~~
~~The generator's capability curve (D-curve) can "shrink" with heating and "expand" with cooling of the machine.~~
The ability of a generator to produce or absorb reactive power (MVAr) is limited by generator heating considerations. A generator is able to produce or absorb only a small amount of real power (MW). As the generator's production of real power decreases, its ability to produce or absorb power increases. Figure 3.1-1, called a capability curve or a D-Curve, is representative of generators limiting characteristics. The capability curve can "shrink" with heating and "expand" with cooling of the machine.

3.2 Responsibilities for Service

The NYISO directs the Generating Resources to operate within their tested reactive capability limits. The scheduling of ~~voltage support service~~VSS is the responsibility of the NYISO and Transmission Owners.

- NYISO — The NYISO coordinates the NYS Power System voltages throughout the NYCA.
- Transmission Owners — Transmission Owners are responsible for the local control of the reactive power resources that are connected to their network.
- Suppliers — To qualify for payments, Suppliers of ~~voltage support service~~VSS must provide a Resource that has an ~~AVR~~ Automatic Voltage Regulator and has successfully performed Reactive Power (MVAr) capability testing in accordance with the NYISO Procedures and prevailing industry standards. Suppliers are expected to operate their Resources within these demonstrated reactive capability limits. ~~Voltage Support Service~~VSS includes the ability to produce or absorb Reactive Power within the Resource's tested reactive capability, and the ability to maintain a specific voltage level under both steady-state and post-contingency operating conditions subject to the limitations of the Resource's tested reactive capability.

3.3 Payment for Service

This section describes the payments for ~~voltage support service~~VSS and covers the following:

- ~~3.4~~ Method for determining payment
- Payments made to suppliers of ~~voltage support service~~VSS
- Payments for ~~voltage support service~~VSS by non-utility generators
- Payment for lost opportunity cost
- Payments made by transmission customers and LSEs

For more information, see NYISO ~~Manual for~~ Accounting & Billing Manual.

3.3.1 Method for Determining the Payments for Voltage Support Service

Payments to Generators and synchronous condensers eligible for ~~Voltage Support Service~~VSS are based upon a fixed dollar amount per MVAr as specified in the NYISO Market Services Tariff Rate Schedule 2 and MVAr capability as determined by annual capability testing performed by the generator and verified by the NYISO.

3.3.2 Payments made to Suppliers for Voltage Support Service

The rate provided in Rate Schedule 2 shall be used to calculate payments to all eligible Suppliers providing ~~Voltage Support Service~~VSS as applied on a Resource-specific basis. The NYISO shall calculate payments on an annual basis, and make payments monthly. Suppliers whose Resource(s) meet the requirements to supply Installed Capacity and are under contract to supply Installed Capacity receive one-twelfth the annual payment for ~~Voltage Support Service~~VSS except as noted in

Section 3.3.3 below with respect to Non-Utility Generators. Suppliers whose Generators are not under contract to supply Installed Capacity and Suppliers with synchronous condensers receive one-twelfth the annual payment pro-rated by the number of hours that Generator or synchronous condenser operated in that month, as recorded by the NYISO.

For Non-Utility Generators that are operating under existing power purchase agreements, the entity that is purchasing Energy and/or Capacity under such agreement or providing Transmission Service under that agreement is contacted by the NYISO when the NYISO requires ~~Voltage Support Service~~VSS from the contracted Resource. The NYISO pays holders of the contracts for such Resources, which are operating under existing power purchase agreements, the product of the annual $/MVAr rate for the NYISO and the MVAr capacity of the Non-Utility Generator as described in Section 3.3.3.

3.3.3 Payments for Voltage Support Service Provided by Non-Utility Generators with Existing Power Purchase Agreements

The NYISO pays each holder of a contract for a Non-Utility Generator operating under an existing power purchase agreement, which provides ~~Voltage Support Service~~VSS.

- If that non-utility Generator provides installed capacity, the NYISO will pay it the product of: (1) one -twelfth of the annual $/MVAr rate for NYISO payments to Suppliers of VSS and (2) the lesser of the tested Reactive Power production capability (MVAr) of the Non-Utility Generator or the contract MVAr capability.
- If that non-utility Generator does not provide Installed Capacity, the NYISO will pay it the product of (1) and (2), as calculated above, multiplied by the number of hours in the month the Non-Utility Generator provided VSS divided by the number of hours in the month.

The NYISO calculates and makes payments on a monthly basis.

3.3.4 Payments for Lost Opportunity Cost

A Supplier providing ~~Voltage Support Service~~VSS from a Generator that is In-Service is entitled to receive Lost Opportunity Costs (LOCs) in the event ~~that~~ the NYISO dispatches or directs the Generator to reduce its real power (MW) output in order to allow the unit to produce or absorb more reactive power (MVAr).

The method for calculating LOC is based on the following:

- Real-Time LBMP
- Original dispatch point
- New dispatch point
- Bid curve of Generation supplying ~~Voltage Support Service~~VSS

Figure 3.3.4 graphically portrays the calculation of the LOC for a Generator, which reduced its MW output to allow it to produce or absorb more reactive power (MVAr).

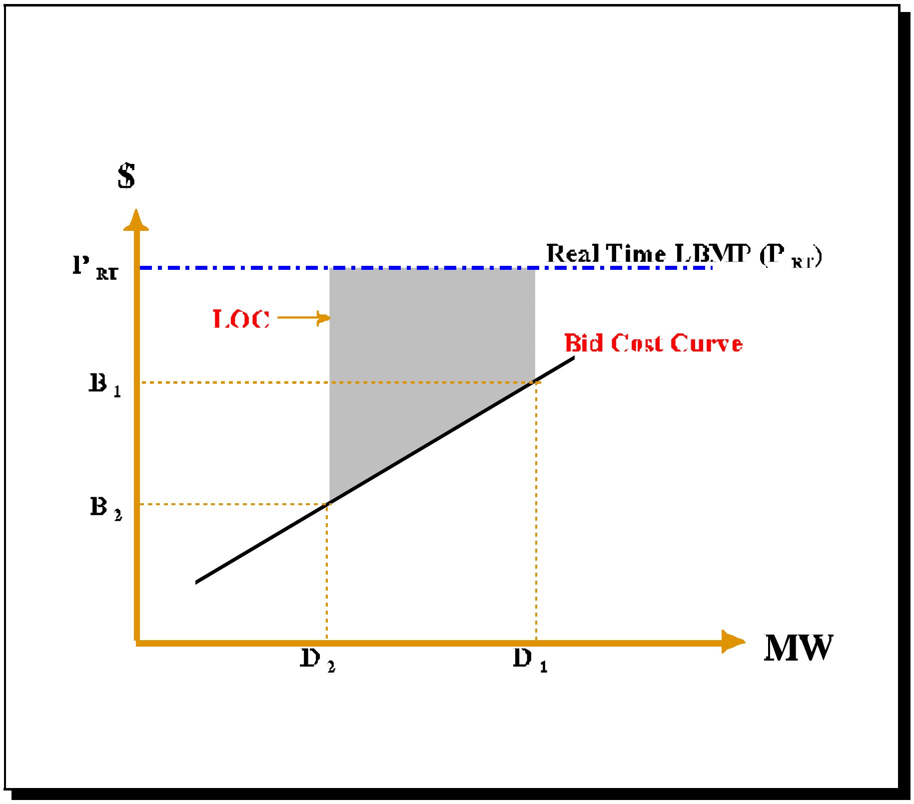


Figure 3.3.4: Method for Calculating LOC

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

Where: P_{RT} = Real Time LBMP
D_1 = Original Dispatch Point
D_2 = New Dispatch Point
Bid = Bid curve for generation supplying voltage support services

3.3.5 Payments made by Transmission Customers and LSEs

Transmission Customers and Load Serving Entity (LSEs) taking service under the NYISO OATT pay the NYISO for VSS associated with energy withdrawals from the transmission system. The NYISO computes the VSS Rate as follows:

The sum of the projected NYISO payments to Suppliers providing Voltage Support including:

- total annual costs eligible for payment.
- any applicable Lost Opportunity Costs to provide ~~Voltage Support Service~~VSS.
- total of prior year payments to Suppliers of ~~Voltage Support Service~~VSS less the total of payments received by the NYISO from Transmission Customers and LSEs in the prior year for ~~Voltage Support Service~~VSS (including all payments for penalties).

- This sum is divided by annual forecasted transmission usage for the year as projected by the NYISO, including Load within the NYCA, Exports, and Wheels Through.

Transmission Customers engaging in Wheels-Through or Exports pay to the NYISO a charge for this service equal to the rate as determined above multiplied by their Energy wheeled in the hour. Load Serving Entities serving loads in the NYCA pay to the NYISO a charge for this service equal to the hourly rate as determined above multiplied by the Energy withdrawn from the transmission system in order to serve that LSEs Load in the hour.

The NYISO calculates the payment hourly and bills each Transmission Customer or LSE monthly.

3.4 Failure to Perform by Suppliers

A resource will have failed to provide voltage support if it:

1) fails at the end of 10 minutes to be within 5% (+/-) of the requested reactive power (VArs) level of production or absorption as requested by the NYISO or applicable Transmission Owners for levels below the resource's demonstrated reactive power capability at Dependable Maximum Net Capability (DMNC).
2) fails at the end of 10 minutes to be at 95% or greater of the resource's demonstrated reactive power capability (tested at its Normal Operating Limit or at 90% of its DMNC, whichever is greater in MW) in the appropriate lead or lag direction when requested to go to maximum lead or lag reactive capability by the NYISO or applicable Transmission Owner.
3) fails to automatically respond, following a system contingency, to produce (or absorb) the reactive power required in accordance with published NYISO (or Transmission Owner) system operating studies.

Any resource that fails to provide voltage support when it is being paid to provide voltage support will be penalized in accordance with Sections 3.4.1 and 3.4.2.

3.4.1 Failure to Respond to NYISO's Request for Steady State Voltage Control

a) An installed capacity provider of voltage support that fails to provide steady-state voltage support on a given day will forfeit 1/12th of the annual payment that resource would have received for providing voltage support, and must reimburse the NYISO for any lost opportunity costs paid to replacement sources of steady-state voltage support.
b) A non-installed capacity provider of voltage support that fails to provide steady-state voltage support on a given day will forfeit the voltage support payment received by that resource in the last month in which that payment was positive (as a proxy for 1/12th of the annual payment that resource would have received for providing voltage support), and must reimburse the NYISO for any lost opportunity costs paid to replacement sources of steady-state voltage support.

c) A provider will be disqualified as a provider of voltage support after it fails to provide steady-state voltage support on three separate days within a 30-day period.

Reinstatement of Payments

The NYISO may reinstate payments once the Supplier complies with the following conditions to the NYISO's satisfaction:

- the Supplier's Resource must successfully perform a Reactive Power (MVAr) capability test, and
- the Resource must provide ~~Voltage Support Service~~VSS for 30 consecutive days without any compliance failures. No payments for ~~Voltage Support Service~~VSS or LOC are made to the Supplier during this period.

3.4.2 Failure to Provide Voltage Support Service when a Contingency Occurs on the NYS Power System

a) An installed capacity provider of voltage support that fails to provide voltage support following a contingency on a given day will forfeit 1/12th of the annual payment that resource would have received for providing voltage support on the first such occurrence, and 1/4th of the annual payment that resource would have received for providing voltage support on the second such occurrence. Generators that fail to provide voltage support following contingencies will not be charged lost opportunity costs for replacement sources of voltage support because there will not be enough time to arrange for replacement sources.

b) A non-installed capacity provider of voltage support that fails to provide voltage support following a contingency on a given day will forfeit the voltage support payment received by that resource in the last month in which that payment was positive (as a proxy for 1/12th of the annual payment that resource would have received for providing voltage support) on the first occurrence. Additionally, it will forfeit the payment received by that resource in the last three months in which those payments were positive (as a proxy for 1/4th of the annual payment that resource would have received for providing voltage support) for the second failure.

c) A provider will be disqualified as a provider of voltage support after it fails to provide voltage support following a contingency on two separate occasions within a 30-day period.

Reinstatement of Payments

In addition, the Supplier that is in violation is prohibited from receiving ~~Voltage Support Service~~VSS payments for the non-complying Resource until the Supplier complies with the following conditions to the NYISO's satisfaction:

- the Supplier's Resource successfully performs a Reactive Power (MVAr) capability test, and
- the Resource provides ~~Voltage Support Service~~VSS for 30 consecutive days without any compliance failures. No payments for ~~Voltage Support Service~~VSS or LOC are made to the Supplier during this period.

3.5 Generator Reactive Capability Testing

The purpose for capability testing is to establish a uniform procedure of determining, confirming, and documenting the reactive capability of generators used for real-time system voltage control. This procedure provides the NYISO with accurate and timely information on the reactive capability of the generating units.

Units to be Tested

All resources that are used for ~~voltage support service~~VSS must be tested in accordance with this procedure. All tests will be coordinated by ~~ISO~~NYISO and the Transmission Owner in whose service territory the unit is located. Test data for any unit will be accepted and incorporated into the appropriate databases.

Definitions

Lagging MVAr — Reactive power that is generated out of a generator and into the power system. By convention, lagging MVAr is a positive (+) number.

Leading MVAr — Reactive power that is absorbed by a generator out of the power system. By convention, leading MVAr is a negative (-) number.

3.5.1 Frequency of Testing

Each generator and synchronous condenser providing this service must be tested at least once each calendar year to demonstrate maximum lagging and leading MVAr capability. Leading MVAr capability can be demonstrated any time during the year while lagging MVAr capability can be tested only during the peak load capability period of the year for the Transmission District where that resource is located. More frequent tests may be performed by the Suppliers. Failure to perform required testing will result in the forfeiture of the voltage support payments.

3.5.2 Test Procedure for Generators

Each Supplier has the responsibility to conduct reactive capability testing on its respective units. The tests are to be carried out under normal operating conditions. Extreme measures are not to be taken to avoid overstating a unit's normally expected reactive capability. Both leading and lagging MVAr are to be measured at the generator terminals. Measurements should be made with the unit operating with normal hydrogen pressure (or other normal coolant conditions). The ~~Transmission Provider~~Transmission Owner Operator is responsible for coordinating the test with the respective plant. Each ~~Transmission Provider~~Transmission Owner Operator notifies the NYISO at least one hour prior to the initiation of generator MVAr testing. The NYISO in turn notifies all other affected ~~Transmission Provider~~Transmission Owners.

Annual Tests

To test maximum lagging MVAr capability, the unit being tested must be operated at its normal MW Operating Capability. The unit is then moved to maximum lagging MVAr and held at this point for a minimum of one hour.

To test maximum leading VAR capability, the unit being tested is operated at its normal MW low limit. The unit is move to maximum leading MVAr and held at this point for a minimum of one hour.

For Nuclear units and units with normal MW low limits equal to normal MW operating capability, both leading and lagging MVAr capability are tested with the unit operating at its normal MW operating capability. Maximum lagging and leading MVAr test points are held for a minimum of one hour each.

Test Results

Attachment ~~B~~ A shows the form that is used to document the test results that are submitted by the Supplier to the NYISO within five (5) business days after the test. If the lagging and leading MVAr capability tests are performed on different dates, then the results can be submitted separately.

3.5.3 Test Procedure for Synchronous Condensers

Each synchronous condenser providing this service will be required to demonstrate the maximum leading and lagging MVAr capability it can maintain for one hour.

3.6 Voltage Support

The following procedures apply to ~~voltage support service~~VSS.

3.6.1 Request for Voltage Support Service

The NYISO may request corrective actions from voltage support facilities that are already in service and available. The procedures for Real-Time voltage control are covered in the *NYISO ~~Manuals for~~ Emergency Operations* and *Transmission & Dispatching Operations Manuals*.

3.6.2 Automatic Voltage Regulator Availability

Supplier Actions:

The supplier must perform the following:

1) Provide immediate notification to the NYISO whenever its AVR is forced out of service or prior to removal from service for maintenance.
2) Notify the NYISO of the estimated time for completion of needed AVR repairs or scheduled maintenance.

4. Regulation & Frequency Response Service

This section describes the regulation and frequency response service.

4.1 Description

Regulation and frequency response services are necessary for the continuous balancing of resources (generation and NY Control Area interchange) with load, and to assist in maintaining scheduled Interconnection frequency at 60 Hz. This service is accomplished by committing on-line generators whose output is raised or lowered (predominately ~~through the use of~~using Automatic Generation Control ~~[~~(AGC~~]~~) as necessary to follow moment-by-moment changes in load. The service is in addition to operating reserve services required for system contingency purposes. The NYISO offers regulation and frequency response services to serve Load within the NY Control Area.

The NYISO establishes the regulation and frequency response requirements consistent with criteria established by North American Electric Reliability Council (NERC~~) which~~), which may vary by hour and by season. Seasonally, the NYISO shall post the hourly regulation and frequency response requirements and, prior to the start of the season, shall present the regulation and frequency response requirements to the System Operation Advisory Subcommittee (SOAS) for discussion and comment. Should the NYISO determine that it intends to establish regulation and frequency response requirements for any hour that are lower than any requirement for that hour in the seasonal regulation and frequency response requirements published as of March 1, 2004, it shall present, prior to posting, its analysis and the revised requirement to the Operating Committee for approval. Should the NYISO determine, for reliability reasons, that it intends to establish regulation and frequency response requirements for any hour that are higher than the requirement for that hour currently in effect, it shall raise the requirement, issue a notice as soon as possible, repost the hourly regulation and frequency response requirements for that season, and discuss its adjusted regulation and frequency response requirement for that hour at the next regularly scheduled Operating Committee meeting. Shortly after the end of each Capability Period, the NYISO shall present SOAS ~~with an analyses~~with an analysis of the regulation performance in that Capability Period. The NYISO also establishes generation resource performance measurement criteria and procedures for bidder qualification and for the disqualification of bidders that fail to meet such criteria.

4.2 Source of Service

Regulation service is bid into the market by individual units that have AGC capability and that wish to participate in the regulation market. Generating Resources are not obligated to participate and provide regulation service unless they have bid for Regulation and that bid has been accepted.

The NYISO selects regulation service in the Day-Ahead Market from qualified Generating Resources that bid to provide regulation service. Market Participants may submit bids to the NYISO for regulation services up to the Real-Time Market market--closed time (75-minutes prior to the operation hour).~~, up to 90 minutes ahead of the Balancing Market, but are not selected for service unless the NYISO determines that additional services are required.~~

The bid evaluation program validates a regulation bid and returns a message to the bidder indicating that data supplied is either valid or is rejected. Rejected Bids (or any bid) may be changed and resubmitted prior to market closing time. Bid information includes:

- Regulation response rate, in MW/min
- Regulation availability/price, in $/MW

The NYISO Market Participants User's Guide ~~Manual for Day-Ahead Scheduling~~ describes the bidding protocols and the checks that the NYISO makes to ensure validity. Regulation capacity (or regulating margin) is calculated as the regulation response rate times five minutes.

Figure 4.2 shows how regulation capacity is defined with respect to a unit's operating range, for the situation without Reserve activation. See Section 6 for a description of what happens when Reserve is activated.

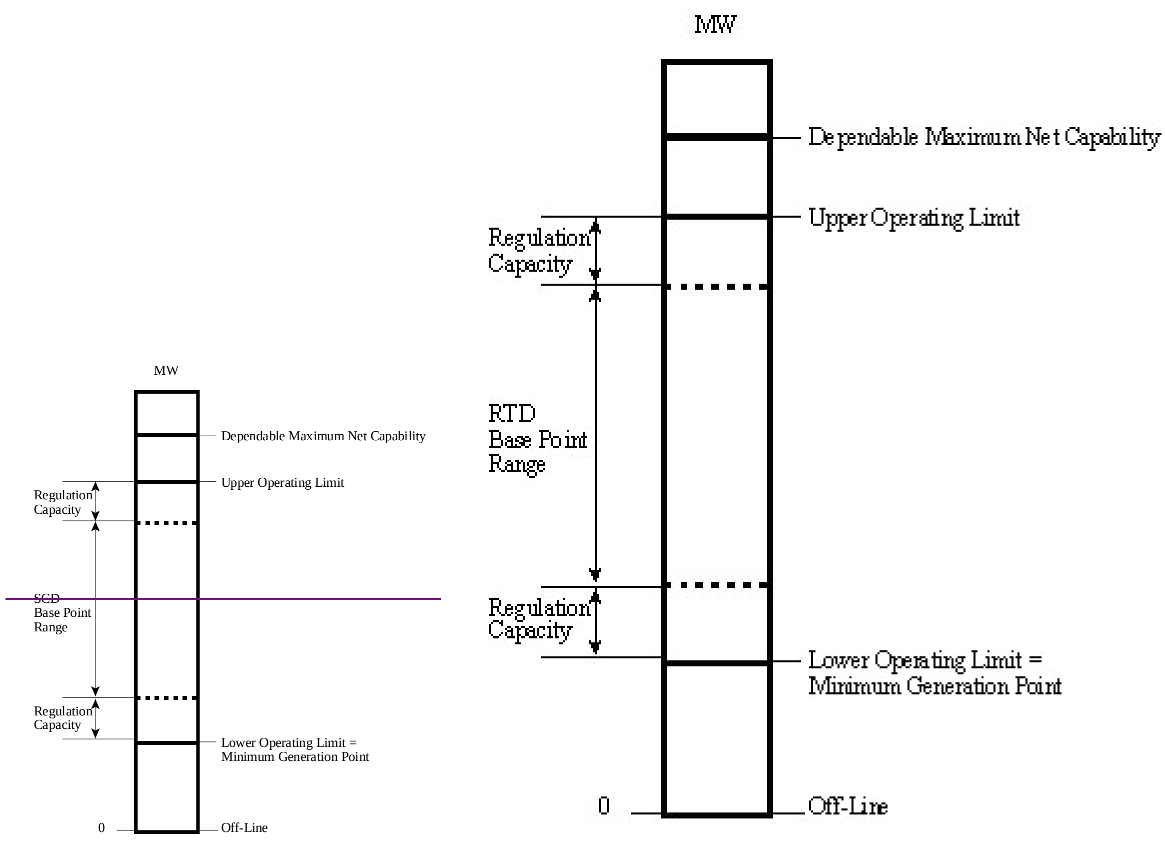


Figure 4.2: Generating Unit Operating Characteristics

There are up to five~~three~~ response rates that are bid by the suppliers:

- *Normal Response Rate (NRR)* — ~~tone, two, or~~There may be up to three ~~normal This~~ response rates ~~may be specified for~~given with each generator. They are used ~~by RTD~~ under non-reserve pickup conditions~~response rate is used by SCD under non-reserve pickup conditions~~.

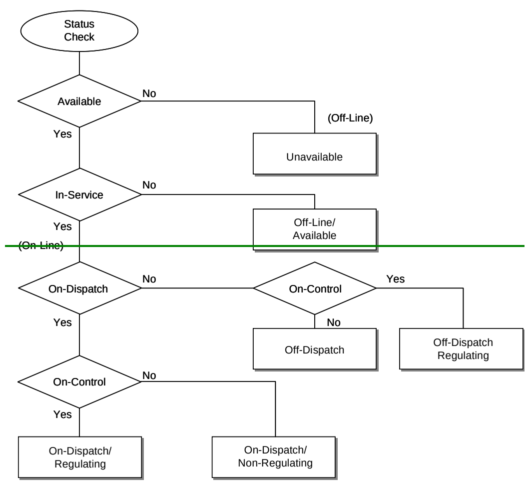
- *Regulation Response Rate (RRR)* — This response rate is given with the regulation bid and must be no less than 1 MW/minute.
- *Emergency Response Rate (ERR)* — This response rate is used ~~by SCDRTD~~ under reserve pickup conditions. ERR must be greater than or equal to ~~NRR~~the capacity weighted average of the ~~three~~ normal response rates.~~.~~

Individual units may bid into the market as groups of units, providing the units are pre-qualified to be bid and operated together as though they are a single unit for all generator bid services (units participating as part of a group are not allowed to bid individually or as part of another group). Pre-qualification specifications for units to bid as a group include metering support, billing, and performance measurements as if a single unit.

4.3 Scheduling of Service

As specified in Section 4.1, regulation requirements are determined by the NYISO consistent with industry standards set by NERC. The regulation requirements may include locational requirements and consider transmission constraints. Automatic Generation Control signals for regulation service are transmitted to the individual units via the Transmission Owners or directly from the NYISO, or both.

4.3.1 Generating Unit Operating States



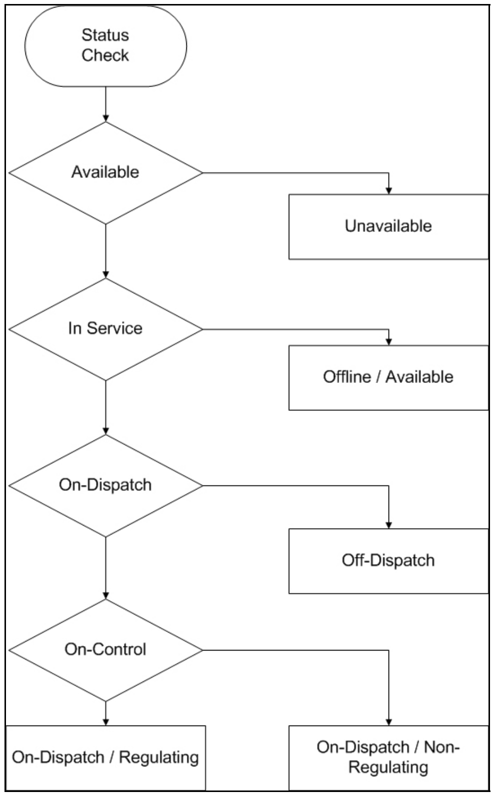


Figure 4.3.1-1: Generating Unit Operating States

Generating units have the NYISO operating states as shown in Figure 4.3.1.

- ***Unavailable* –** The unit is Off-Line and is not available for any ancillary services contribution.
- ***Off-Line/Available* –** The unit is Out-of-Service and Off-Line, but is available for ancillary services contribution.
- ***Off-Dispatch* –** The unit is In-Service and On-Line and is ~~typically~~ not under automatic control. ~~The unit is operated at a specified pre-scheduled output level, which can change on the ¼ hour. RTD emulates this schedule and produces a corresponding basepoint for the unit.~~This unit's RT schedule is predetermined. Schedule changes may occur only on the quarter hour.
- ***On-Dispatch/Non-Regulating* –** The unit typically is not under automatic control. ~~RTD schedules and produces a~~ The basepoint for the unit is normally updated every five minutes. The unit does not participate in Regulation.
- ~~***On-Dispatch/Non-Regulating* – The unit typically is not under automatic control. RTD schedules and produces a basepoint for the unit. The unit does not participate in Regulation, either by its own choice or the NYISO's choice.**~~
- ***On-Dispatch/Regulating* –** The unit is under automatic control. The unit has an Energy schedule that is established by RTD. The unit participates in Regulation as directed by AGC and, thus, may be requested to deviate from its RTD schedule.
- ~~*Unavailable* – The unit is Off-Line and is not available for any reserve contribution.~~

~~•*Off-Line/Available* The unit is Out-of-Service and Off-Line, but is available for reserve contribution.~~

~~•*Off-Dispatch* The unit is In-Service and On-Line and is typically not under automatic control. The unit is operated at a specified pre-scheduled output level which can change on the hour. Security Constrained Dispatch (SCD) emulates this schedule and produces a corresponding basepoint for the unit.~~

~~•*Off-Dispatch/Regulating* The Unit is In-Service and On-Line. The Unit is operated at a specified pre-scheduled output level which can change on the hour. SCD emulates this schedule and produces a corresponding basepoint for the unit. The unit participates in Regulation as directed by AGC and, thus, may be requested to deviate from its SCD schedule.~~

~~•*On-Dispatch/Non-Regulating* The unit typically is not under automatic control. SCD schedules and produces a basepoint for the unit. The unit does not participate in Regulation.~~

- ~~*On-Dispatch/Regulating* The unit is under automatic control. The unit has an Energy schedule that is established by SCD. The unit participates in Regulation as directed by AGC and, thus, may be requested to deviate from its SCD schedule.~~

4.3.2 Regulation Capacity Scheduling

Regulation capacity is allocated to each unit that was selected to supply regulation, according to the expected regulation response rate (RRR) times 5 minutes.

Regulation capacity is comprised of two regions. The upper region is bounded by the unit upper operating limit. The lower region is bounded by the minimum generation point. Each region is equal to the regulation capacity accepted for that Unit. (See Figure 4.2)

Commitment for Additional Regulations

The NYISO may commit additional generation resources in the real-time market to provide regulation if any of the following conditions exist:

1) Insufficient regulation MW is bid into the Day-Ahead Market.
2) Units that were scheduled in the Day-Ahead Market to provide regulation services are not available in real-time.
3) More regulation services are required than had been anticipated would be needed in the Day-Ahead Market.

Replacement Regulation

Units, including those not awarded a forward contract to provide regulation in the First Settlement commitment process, may bid into the Second Settlement market for regulation. A generator providing replacement regulation in the real-time market will be paid ~~availability~~ based on:

~~Availability of t~~1) The Real-Time market clearing price (MCP) for regulation

2) Its Scheduled regulation in MWs

3) The length of the period of time during which it provides regulation.

Regulation Default

~~Under RTS, a~~A unit with a day-ahead regulation schedule that cannot provide regulation in real-time will receive a zero real-time regulation schedule ~~from RTD~~ and buy out of its day-ahead commitment. There are no other penalties for a "default."

~~Failure to provide scheduled regulation is treated as follows:~~

~~A regulating generator will be designated as defaulting (and thereby become responsible for replacement regulation costs) during all periods that the generator has a real-time status of "Off-Control."~~

~~A defaulting regulating generator will be charged the real-time regulation price during the period following its default.~~

~~Regulation capacity is allocated to each unit that was selected to supply regulation, according to the expected regulation response rate (RRR) times five minutes. Security Constrained Dispatch honors each unit's regulation capacity.~~

~~Regulation capacity is comprised of two regions. The upper region is bounded by the unit upper operating limit and the SCD Base Point Range. The lower region is bounded by the SCD Base Point Range and the generation point. Each region is equal to the total regulation capacity accepted for that Unit. (See Figure 4.2)~~

~~The NYISO may commit additional generation resources in the real-time market to provide regulation for that day if any of the following conditions exist:~~

- ~~insufficient regulation MW is bid into the day-ahead market.~~
- ~~units that were scheduled to day-ahead to provide regulation services are unavailable.~~
- ~~more regulation services are required than had been anticipated would be needed in the day-ahead market.~~

~~Units, including those not awarded a forward contract to provide regulation in the First Settlement commitment process, may bid into the Second Settlement market for regulation. A generator providing replacement regulation in the real-time market will be paid availability based on: (a) the Real-Time market clearing price (MCP) for availability; (b) its availability in MW; and (c) the length of the period of time during which it provides regulation.~~

~~A regulating generator will be designated as defaulting (and thereby become responsible for replacement regulation costs) during all periods that the generator has a real-time status of "Off-Control".~~

~~A defaulting regulating generator will be charged the day-ahead regulation price during the period following its default, but preceding replacement of its regulation. During the period its regulation is being replaced, the defaulting generator will pay the higher of the day-ahead or the real-time regulation market clearing price.~~

~~If multiple regulation generators default, any payments for replacement regulation will be shared proportionally by those defaulting generators.~~

4.3.3 Control Signals to Satellite Control Centers

Control signals designating the value of Unit Desired Generation (UDG) ~~Values~~ for each unit are sent to the satellite control centers every six seconds.

~~In the NYISO's AGC, only units with accepted regulation Bids are required to regulate. Since all regulating units are paid the same availability clearing price per MW, their participation in PCEArea Control Error (ACE) is proportional to their individual accepted MW/minute response rate as a percentage of the total accepted MW/minute response rate.~~

4.3.4 Regulation Service

The AGC function ~~will~~ calculates an area control error and allocate this error to selected regulating units in proportion to the amount of their scheduled regulations. AGC will determine the UDG for each unit by combining the unit's regulation requirement (if any) with its ramped basepoint derived from its RTD 5-minute basepoint. The NYISO computer system will send UDGs to TOs that will in turn retransmit the UDGs to generating units in their control area. Regulation penalties for all NYCA units will be assigned by the NYISO directly to individual generating units based on their monitored performance.

For detailed information on AGC see Attachment C of this ~~m~~Manual.

The amount of regulation capacity (MW) and response rate (MW/Minute) that is required for the NY Control Area is established by the NYISO and can vary on a seasonal and hourly basis. The *NYISO Transmission & Dispatching Operations Manual* describes how the regulation requirements are defined for the New York Control Area.

~~Regulation service is accomplished in two phases:~~

~~***Phase I: Interim Automatic Generator Control (IAGC)***~~

~~The IAGC will calculate Pool Control Error (PCE), Satellite Control Error (SCE), Area Participation Factor (APF), Unit Participation Factor (UPF), Unit Control Error (UCE), and Unit Desired Generation (UDG) control signals. The IAGC is outlined below:~~

~~1) All control units will be selected by the SCUC based on the NYISO requirement (in MW/min), submitted bid prices, and locational considerations. Bids will be submitted by the Market Participants through the Bid/Post/OASIS Market Information System (MIS). The price paid for regulation (dollars per MW/min) would be based on the market-clearing price established by SCUC. These payments would be funded by NYCA loads, non-regulating generators that are off their basepoint schedules, and regulating generators that are not meeting regulation obligations.~~

~~2) An Area Participation Factor (APF) for a Transmission Owner (TO) control area will be calculated based on the MW/min of regulation of the generating units selected by SCUC that happen to reside in that control area divided by the total NYISO MW/min chosen. A TO control area could have zero units chosen and therefore a zero APF.~~

~~3) Individual Unit Participation Factors (UPFs) will be calculated based on the MW/min of regulation for those generating units selected by SCUC that happen to reside in the TO control area divided by the total MW/min chosen in that control area.~~

~~4) The Security Constrained Dispatch (SCD) program will trim the limits for the selected regulation control units to insure that adequate regulating margin exists.~~
~~5) The New York Control Area (NYCA) Desired net Interchange (DNI) will be calculated every six seconds so that external schedule changes are ramped on a straight line basis.~~
~~6) Six-second setpoints will be produced for all on-line units. These will be interpolated from the last two sets of SCD produced basepoints. Five-minute basepoints will be sent to the TO. As work progresses toward End-State AGC implementation, 6-second basepoints may be sent out when applicable.~~
~~7) Pool Control Error (PCE) will be calculated (same as done by NYPP) as follows:~~

$$PCE = (DNI\text{-}IPS) - (ANI+NIO) - (fb \times (f\text{-}fo))$$

~~Where:~~

~~DNI = Desired Net Interchange for NYCA~~
~~IPS = Inadvertent Payback Setter~~
~~ANI =Actual Net Interchange for NYCA~~
~~NIO = Net Interchange Offset (Sum of TO Offsets)~~
~~fb = Frequency Bias Constant~~
~~f-fo = Frequency Deviation~~

~~8) Satellite Control Error (SCE) for each TO Area will be calculated as follows:~~

$$SCE = APF \times (PCE - \Delta Gen) + (SBF \times \Delta Gen))$$

$$\cancel{SCE = APF \times (PCE - ((1 - SBF) \times \Delta Gen))}$$

$$SCE = APF \times (PCE - ((1 - SBF) \times \Sigma NYCA_{Actual} - \Sigma NYCA_{Setpoint})))$$

~~Where:~~

~~APF = Area Participation Factor for TO's Satellite Control Area~~
~~PCE = Pool Control Area~~
~~SBF = System Balancing Factor (variable from 0.0 to 1.0, manually adjusted by the NYISO for optimum New York Control Area (NYCA) performance)~~
~~ΔGen =$\Sigma NYCA_{Actual} - \Sigma NYCA_{Setpoint}$~~
~~$\Sigma NYCA_{Actual}$ = Total NYCA Actual Generation~~
~~$\Sigma NYCA_{Setpoint}$ = Total NYCA 6-Second AGC Setpoints~~

~~9) Compliance with the NERC CPS-2 Performance Standard will be the primary objective for the NYISO when determining the SBF. This standard consists of a control range with upper and lower bounds on ACE determined by NERC. Compliance with CPS-2 is measured on the average ACE to be within the upper and lower control bounds during a 10-minute interval. If the previous interval's NYCA measured CPS-2 performance violates the NERC performance standard, the SBF shall be set to 1.0 so all regulation capacity is used to maximize control performance. When the previous interval's NYCA measured CPS-2 performance is within the NERC performance standard, the NYISO may adjust the SBF to values lower than 1.0 to minimize the NYCA inadvertent energy interchange.~~

~~*Regulating Generators:*~~

~~In this interim phase, the NYISO generally will use existing NYPP AGC software to produce nominal 6-second Unit Desired Generation (UDG) Set-Points for each regulation provider. These UDG signals will be sent to Transmission Owners (TOs) for direct pass-through to the appropriate generators. NYISO performance tracking will recognize and assess performance penalties directly to the appropriate individual generators.~~

~~If a TO is not initially capable of directly passing through the UDG signals, the NYISO will calculate Satellite Control Errors (SCE) and Unit Participation Factors (UPF) for the aggregate of all regulation providers in that TO's area. The NYISO will send these SCE and UPF signals to the TO every 6 seconds. The TO, in turn, will determine individual Unit Control Errors (UCE) by applying the appropriate UPF to the SCE, and controlling the respective generators using existing TO algorithms. The NYISO will track the performance of each individual regulating generator in the TO area, and aggregate that performance into a single aggregate TO regulating generator. The NYISO will assess a penalty to the TO based on that aggregate regulating generator performance compared to the SCE signal sent by the NYISO to the TO. The TO will then allocate regulation penalties to the appropriate generators based on their individual performance.~~

~~*Non - Regulating Generators*~~

~~The NYISO will use SCD software to provide Real-Time energy schedules for all generators in the New York Control Area (NYCA) that are observable by the NYISO. These energy schedules will be calculated and sent at SCD Base-Point signals nominally every five minutes. Generators that are "On-Line" but "Off-Dispatch" will be assigned SCD Base-Points equal to their pre-determined energy schedules. For schedule changes, to determine ramped Set-Points on a six-second basis, the NYISO will perform a linear interpolation between the nominal five-minute SCD Base-Points. Both the SCD Base-Points and the interpolated six-second Set-Points will be sent to the appropriate TO at their respective time intervals for generation dispatch.~~

~~*Phase II: End-State AGC*~~

~~In the End-State AGC phase, TOs will discontinue Satellite AGC operation and simply retransmit UDGs from the NYISO to individual generating units. The End-state AGC function will calculate area control error and allocate this error to selected regulating units. End-state AGC will determine the UDG for each unit by combining the unit's regulation requirement (if any) with its ramped basepoint derived from its SCD five-minute basepoint. The NYISO computer system will send UDGs to TOs that will in turn retransmit the UDGs to generating units in their control area. Regulation penalties for all NYCA units will be assigned by the NYISO directly to individual generating units based on their monitored performance.~~

~~For detailed information on interim and end-state AGC, see Attachment C.~~

~~The amount of regulation capacity (MW) and response rate (MW/Minute) that are required for the NY Control Area are established by the NYISO and can vary on a seasonal and hourly basis. *NYISO Manual for Transmission & Dispatching Operations* describes how the regulation requirements are defined for the NY Control Area.~~

~~4.3.5.~~4.3.5 AGC & ~~SCD~~ RTD Program Response

The AGC program ~~is limited to~~ uses ~~either~~ the regulation response rate. The ~~SCD~~ RTD program ~~is limited to~~ uses either the normal response rate or the emergency response rate, depending on reserve activation. The reserve Pick Up dispatch will use all dispatchable ~~and class B~~ units, which includes units ~~that are not being paid reserve availability~~both with and without a reserve schedule. Units ~~supplying reserve availability~~ will have base points calculated using the higher of normal and Emergency Response Rates.

In extreme cases when ~~Pool Control Error (PCE~~ACE~~)~~ exceeds the total available response from accepted regulation bidders, the remaining ~~PCE~~ ACE is distributed in proportion to this ramp rate; however, some quantization is needed to avoid very small schedule changes, proportionally over all regulating resources. ~~If this condition persists, t~~The NYISO Shift Supervisor may ~~request SCD RTD to run in shorter than five-minute intervals~~run RTD-CAM to try to eliminate the imbalance. Alternatively, when more regulation services are required, the NYISO requests more regulation capacity from the regulation Real-Time market.

For small ~~PCEs~~ACEs, a minimum ~~PCE~~ ACE distribution value is established by the NYISO such that small ~~PCEs~~ ACEs are distributed to only a few (or one) units.

~~4.4.~~4.4 Performance Criterion

The NYISO has established the following:

- ~~4.5~~ generator performance measurement criterion, and
- procedures to disqualify Suppliers using Generators that consistently fail to meet the criterion.

~~4.4.1.~~4.4.1 Performance Tracking

The NYISO has a Performance Tracking System (PTS) to monitor the performance of Generators that provide Regulation service. Payments by the NYISO to each Supplier of this Service are based in part on the Generator's performance with respect to expectations. The PTS will also be used to determine penalties assessed to non-regulating generators that do not follow their ~~SCD~~ RTD basepoints, thereby increasing the regulation burden.

Figure 4.4.1-1 illustrates a regulating unit that has perfect performance and Figure 4.4.1-2 illustrates a regulating unit with performance errors.

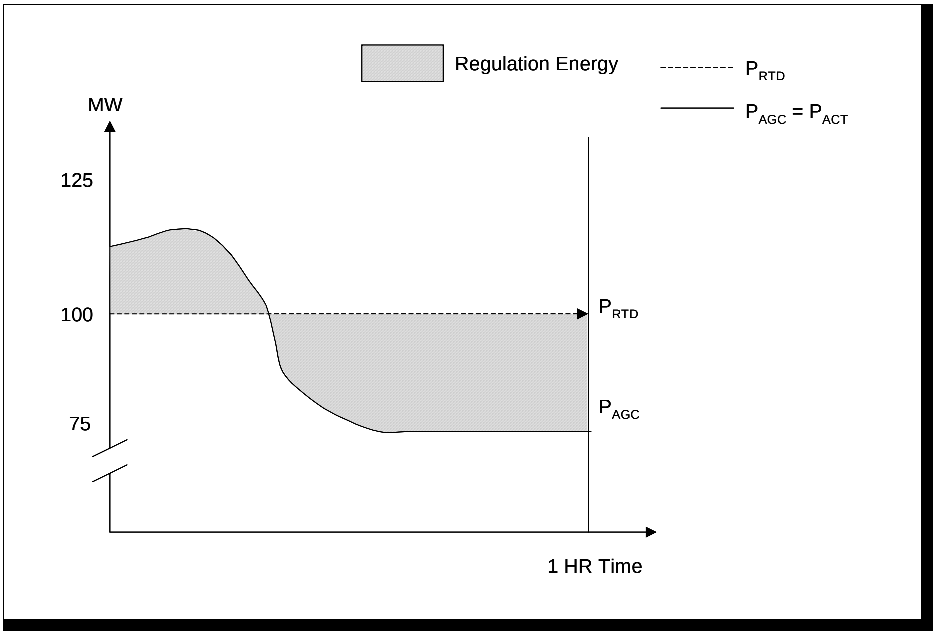


Figure 4.4.1-1: Perfect Performance

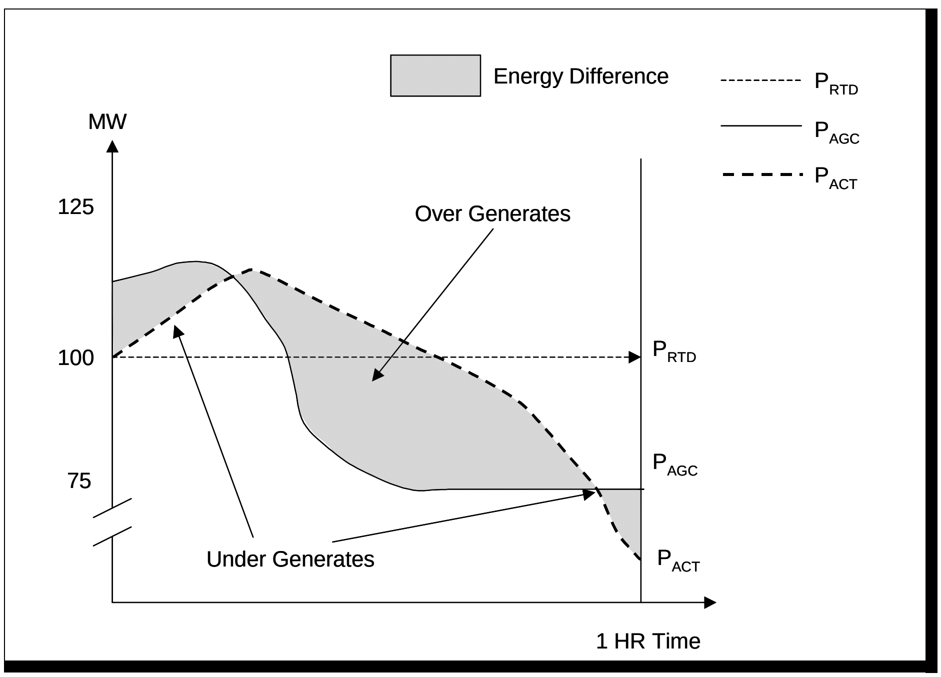


Figure 4.4.1-2: Error in Performance (30 Second band-width not included)

~~The rate at which r~~Regulation resources ~~will be~~are required to change their output level ~~will be consistedat~~ a rate consistent with the amount of regulation each resource has been scheduled to provide.

Regulation resources will not receive additional ~~availability~~ payments for following AGC signals that call for them to provide more regulation than they have been scheduled to provide; but they will be paid for any additional energy they produce as a result of following such signals.

~~Performance Penalty~~ Performance Adjustment

Attachment D of this ~~m~~Manual presents a detailed description for the calculation of regulation performance penalties.

~~Deferral of Regulation Performance Penalties~~

~~Attachment F of this manual describes the rules to provide PURPA contract parties, certain intermittent resources, and certain NYC steam turbines in interim deferral from billing for regulation performance penalties~~.

~~4.4.2. Regulation Performance Penalty~~

~~Regulating Units~~

~~A 30 second bandwidth for regulation providers will be established and bounded by the highest and the lowest of the last five actual AGC signals and the last five modified AGC signals sent to that unit (assuming a nominal six-second AGC cycle), where the modified signal is computed by adjusting the actual AGC signal sent to a regulation provider as necessary in order to ensure that the regulation provider could follow the modified signal without being required to exceed its regulation ramp rate. Generators whose output is within this bandwidth will not incur regulation penalties. Generators whose output is outside this bandwidth will incur penalties for the amount by which they are outside their bandwidth.~~

~~Transmission Provider~~

~~A similar performance calculation is applied to all the regulating units as a single block. Financial penalties for poor performance will be assessed on a Transmission Provider basis.~~

~~Off-Dispatch & On-Dispatch/Non-Regulating Units~~

~~Figure 4.4.2 shows how financial penalties are assessed to Off-Dispatch and On-Dispatch/Non-Regulating units for causing other units to regulate.~~

~~Calculation of Average Absolute Unit Control Error (AAUCE)~~

~~The average absolute unit control error is derived from a unit's deviation of the actual generation of the unit from the 30-second minimum and maximum of the predicted desired generation of the unit. One complication to this concept is that during periods where the real-time ACE is greater than the regulation requirement, the unit desired generation (UDG) will exceed the regulation ramp rate. The AAUCE for each regulating generator measures the amount by which its actual output falls outside this 30-second bandwidth. This section describes how the AAUCE for regulating generators is calculated, and provides an example illustrating that calculation.~~

~~Define A_{it} as the AGC signal sent to regulating generator i at time t, R_i as the number of MW/minute of regulation provided by regulating generator i, and M_{it} as the modified AGC signal for regulating generator i at time t (with the modification correcting the AGC signal to ensure that it does not call for a unit to move faster than the number of MW/minute of regulation it is providing). If AGC signals are sent out every six seconds, regulating generator i can be expected to move R_i/10 MW. Then, in most circumstances,~~

$$M_{i,t+1} = \begin{cases} M_{it} + R_i/10, & \text{if } A_{it} > M_{it} + R_i/10, \\ A_{it}, & \text{if } M_{it} - R_i/10 \le A_{it} \le M_{it} + R_i/10, \\ M_{it} - R_i/10, & \text{if } A_{it} < M_{it} - R_i/10. \end{cases}$$

~~This equation means that the modified AGC signal will move up if the previous period's actual AGC signal is above the previous period's modified AGC signal, and that it will move down if the previous period's actual AGC signal is below the previous period's modified AGC signal, but the amount by which the modified AGC signal can move, relative to the previous period's modified AGC signal, can be no greater than $R_i/10$.~~

~~There are two situations in which the above equation would not apply. In each of these situations, the actual AGC signal's relationship to the modified AGC signal has reversed direction (i.e., the actual AGC signal was above the modified AGC signal in one time period and was below it in the next time period or vice versa) and the actual generation level is closer to the new AGC signal than is the modified AGC signal. In such cases, modified AGC signals in future time periods should reflect the degree to which the generator can move toward the AGC signal starting from its actual generation level, rather than starting from its previous modified AGC signal. We can put this into equation form by letting G_{it} represent the amount of energy actually generated by regulating generator i at time t:~~

~~If~~

$$A_{i,t-1} > M_{i,t-1} \text{ and } 2A_{it} - M_{it} < G_{it} < M_{it}, \text{ then}$$

$$M_{i,t+1} = \begin{cases} G_{it} - R_i/10, & \text{if } A_{it} < G_{it} - R_i/10, \\ A_{it} & \text{otherwise.} \end{cases}$$

~~And if~~

$$A_{i,t-1} < M_{i,t-1} \text{ and } 2A_{it} - M_{it} > G_{it} > M_{it}, \text{ then}$$

$$M_{i,t+1} = \begin{cases} G_{it} + R_i/10, & \text{if } A_{it} > G_{it} + R_i/10, \\ A_{it} & \text{otherwise.} \end{cases}$$

~~Then, given this definition of the modified AGC signal, a regulating unit should not be penalized if either (1) its output is in between the maximum or the minimum of the AGC signals sent to it in the last 30 seconds, or (2) it has moved at its regulation ramp rate (at least). In other words, if we define E_{it} as the control error for regulating generator i for the AGC scan occurring at time t, then~~

$$E_{it} = \begin{cases} 0, & \text{if } L_{it} \le G_{it} \le U_{it}, \\ L_{it} - G_{it}, & \text{if } G_{it} < L_{it} \\ G_{it} - U_{it}, & \text{if } G_{it} > U_{it}, \end{cases}$$

~~Where U_{it}, the upper bound of the envelope within which regulating generator i can operate without penalty, is:~~

~~$U_{it} = \max(M_{it}, M_{i,t-1}, M_{i,t-2}, M_{i,t-3}, M_{i,t-4}, A_{i,t-1}, A_{i,t-2}, A_{i,t-3}, A_{i,t-4}, A_{i,t-5})$~~

~~and L_{it}, the lower bound of that envelope, is:~~

~~$L_{it} = \min(M_{it}, M_{i,t-1}, M_{i,t-2}, M_{i,t-3}, M_{i,t-4}, A_{i,t-1}, A_{i,t-2}, A_{i,t-3}, A_{i,t-4}, A_{i,t-5})$~~

~~The AAUCE over an SCD interval for regulating generator i would simply be the average of the control errors E_{it} occurring within that SCD interval.~~

~~**Example**~~

~~The table on the next page illustrates an example in which a unit is scheduled to provide 10 MW/minute of regulation. Initially, the AGC signal sent to that unit (A_{it}) also increases by 10 MW/minute (i.e., by 1 MW every six seconds), but at :36, the AGC signal sent to this unit jumps by 5 MW. After that jump, it continues to increase by 1 MW every six seconds until 1:24. After 1:24, the AGC signal sent to this unit stays constant at 33 MW.~~

~~Initially, this unit's actual output (G_{it}) is 5 MW below the AGC signal sent to that unit. Since 5 MW is equal to the amount that unit has been asked to move in the last 30 seconds (because the AGC signal is initially increasing at 1 MW every six seconds, and (1 MW / 6 sec.) × 30 sec. = 5 MW), this means that this unit's actual output is trailing the AGC signal sent to that unit by 30 seconds. A 30 second lag in response to the AGC signal will not cause a unit to incur a regulation penalty. Therefore, this unit should have a zero control error at times :30 and :36. (Control errors for times :00 through :24 have not been included in the table because the table does not contain complete histories of all AGC signals sent within the 30 seconds preceding each of those times.)~~

~~And, in fact, the equations described above yield a control error (E_{it}) for this unit of zero at times :30 and :36. The table illustrates how the range within which this unit's control error is zero is calculated. At time = :30, for example, L_{it} (the lower bound of this acceptable range) is 15 MW, which was the lowest AGC signal sent within the preceding 30 seconds, while U_{it} (the upper bound of this acceptable range) is 19 MW – the highest AGC signal sent within the preceding 30 seconds. G_{it} falls within the envelope defined by L_{it} and U_{it}, causing the control error to be zero.~~

Time	A_{it}	M_{it}	U_{it}	L_{it}	G_{it}	E_{it}
:00	15	14			10	
:06	16	15			11	
:12	17	16			12	
:18	18	17			13	
:24	19	18			14	
:30	20	19	19	15	15	0
:36	25	20	20	16	16	0
:42	26	21	25	17	17	0
:48	27	22	26	18	18	0
:54	28	23	27	19	19	0
1:00	29	24	28	20	20	0
1:06	30	25	29	21	21	0
1:12	31	26	30	22	22	0
~~1:18~~	~~32~~	~~27~~	~~31~~	~~23~~	~~23~~	~~0~~
1:24	33	28	32	24	24	0
1:30	33	29	33	25	25	0
1:36	33	30	33	26	26	0
1:42	33	31	33	27	27	0
1:48	33	32	33	28	28	0
1:54	33	33	33	29	28	1
2:00	33	33	33	30	28	2
2:06	33	33	33	31	28	3
2:12	33	33	33	32	28	4
2:18	33	33	33	33	28	5
2:24	33	33	33	33	28	5
2:30	33	33	33	33	28	5

$R_i/10 =$ 1

~~While A_{it} jumps upward at :36, M_{it}, which modifies the AGC signal so that it will not be necessary for a unit to exceed its regulation ramp rate in order to follow the AGC signal, continues to increase at 1 MW every six seconds—since that is the regulation ramp rate for this unit. As a result, the gap between L_{it} and U_{it} widens. At time = 1:12, for example, L_{it} is now equal to the lowest modified AGC signal sent within the preceding 30 seconds, which is 22 MW. While the lowest actual AGC signal sent in the last 30 seconds is the 26 MW signal sent at :42, requiring the unit to increase its output to at least 26 MW would have required it to exceed its 10 MW/minute regulation ramp rate. However, while the unit will not be penalized for failing to exceed that ramp rate, it also will not be penalized for doing so. As a result, U_{it} is set equal to 30 MW—the highest actual AGC signal sent in the last 30 seconds. Since G_{it} continues to fall within the envelope defined by L_{it} and U_{it}, the unit's control error continues to be zero.~~

~~The gap between A_{it} and M_{it} begins to close after the A_{it} signal flattens out at 1:24, and as a result the range between L_{it} and U_{it}, which defines zero control error, also begins to decrease. In the time periods immediately following 1:24, the unit continues to increase its output by 1 MW, as it catches up on the 5 MW jump in the AGC signal that occurred at :36, as well as catching up on the 30-second lag that existed before that jump in the AGC signal. As a result, it stays within this envelope, even though the envelope is narrowing, and the unit's control error remains zero. However, at 1:48, the unit's actual output also flattens. At this point, the unit's actual output is 28 MW, which is 5 MW below the AGC signal that is being sent out to the unit. Since the unit had been operating at the low end of the range defined by L_{it} and U_{it}, a positive control error immediately results from its failure to continue to increase its output at its regulation ramp rate until it reaches the 33 MW AGC signal. At time = 2:00, for example, the control error is 2 MW, since the lowest modified AGC signal issued within the last 30 seconds is 30 MW, 2 MW above the unit's actual output level at that time. Finally, at time = 2:30, the control error reaches 5 MW, since the generator's output is 5 MW below the 33 MW AGC signal sent by that unit, the unit has been sending a steady AGC signal over the last 30 seconds, and~~

~~enough time has elapsed so that the unit could have reached an output level of 30 MW if it had continued to increase its output at its 10 MW/minute regulation ramp rate.~~

~~Regulation Charge for Regulation Providers~~

~~Regulation suppliers will pay a penalty to the NYISO for poor regulation performance equal to the AAUCE for each SCD interval, multiplied by the real-time regulation price for that SCD interval, times the ratio of the SCD interval's length to 60 minutes. If there is no real-time market for regulation, then day-ahead prices will be used to determine these penalties for regulation providers.~~

~~Non-Regulating Units~~

~~Generators that are not providing regulation may also be subject to regulation penalties if they do not follow their SCD basepoints and thereby increase the NYCA's regulation burden. However, these units will be permitted a tolerance level. If the deviation between actual output and ramped SCD basepoints does not exceed this tolerance level, then the unit will not be penalized. If this deviation exceeds the tolerance level, the unit will be penalized for the amount by which the deviation exceeds the tolerance level.~~

~~Performance Index~~

~~The deviation tolerance allowed non-regulating units is based on the degree to which regulating units follow their AGC signals.~~

~~A performance index for each regulating generator (PI_{Reg}) is calculated based on a normalization of a unit's control error with respect to its regulation margin. The value being normalized is the average absolute unit control error (AAUCE). A grace value will be awarded all regulating units to compensate for the inherent control delay and imperfect response of any real unit. The grace value will be set by the ISO NYISO NYISO and will initially be set to 10%. The PI_{Reg} will be truncated to a maximum value of 1.0.~~

~~The performance index for each regulating unit is calculated as follows:~~

$$PI_{Reg} = [(Reg\ Margin - AAUCE)/(Reg\ Margin) + 0.10]$$

~~Where:~~

~~Reg Margin = MW of regulation the generator is scheduled to provide. This value can not exceed the greater of five times its RRR.~~

~~AAUCE = Average absolute unit control error~~

~~Control Area Performance Index~~

~~Once each individual PI_{Reg}s has been calculated, the performance index for the Control Area is calculated by averaging the individual PI_{Reg}s.~~

$$NYCAPI_{Reg} = \frac{\sum_{i=1}^{n} (PI_{Reg}(i) * RegMargin(i))}{\sum_{i=1}^{n} RegMargin(i)}$$

~~Where:~~

~~PIReg(i) = The PIReg of unit i~~
~~n = total number of regulating units in the NYCA~~

~~Non-Regulating Unit Deviation Tolerance~~

~~The deviation tolerance will be calculated as a fixed percentage of the generating units OpCap modified by the Control Area regulation performance index from the previous SCD interval. Deviation tolerance is calculated as follows:~~

$$\cancel{DevTol_i = OpCap_i * Fixed\% * NYCAPI_{\mathrm{Reg}}^2}$$

~~Where:~~

~~i = the unit number~~
~~Fixed% = initially set at 1%~~
~~$NYCAPI_{Reg}$ = New York Control Area regulation performance index averaged over the previous week.~~

~~An example would be a 1000MW generating unit has a deviation tolerance of 10MW for the current SCD interval if $NYCAPI_{Reg}$ from the previous week is 1.0 (perfect).~~

~~If $NYCAPI_{Reg}$ from the previous week is 0.9 for the above example then the deviation tolerance becomes 10MW * (0.9)2 or 8.1MW.~~

~~Regulation Charge for Generators Not Supplying Regulation~~

~~As Figure 4.4.2 shows, non-regulation suppliers will pay a regulation penalty to the NYISO if their deviation from their ramped SCD basepoint exceeds this tolerance level. This penalty will be equal to the amount by which the AAUCE for these non-regulating units over the course of an SCD interval exceeds the tolerance level, multiplied by the real-time price of regulation for that SCD interval, times the ratio of the SCD interval's length to 60 minutes.~~

~~If there is no real-time market for regulation, then day-ahead prices will be used to determine these penalties for regulation providers.~~

~~For SCE > 0:~~

~~If AAUCE >Ramp SCD + DevTol~~
~~Then Reg Penalty = (ActGen - Ramp SCD - DevTol) * MCP~~
~~Else Reg Penalty = 0~~

~~For SCE < 0~~

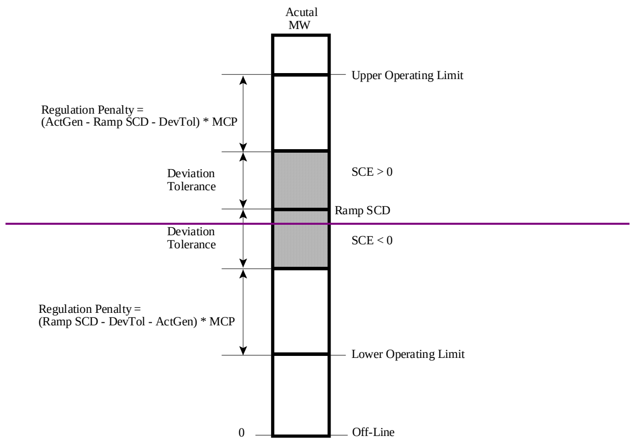
~~If AAUCE < Ramp SCD - DevTol~~
~~Then Reg Penalty = (Ramp SCD - ActGen - DevTol) * MCP~~
~~Else Reg Penalty = 0~~

~~Where:~~

~~SCE = Satellite Control Error~~
~~Ramp SCD = linearly interpolated value between SCD executions, in MW~~
~~ActGen = actual unit output, in MW~~
~~AAUCE = is as defined below~~
~~DevTol = Deviation Tolerance = OP Cap * Fixed Percent * PI2TP/100~~
~~Reg Penalty = Regulation Penalty, in $/MW~~

~~MCP = Market Clearing Price, in $/MW~~

~~Figure 4.4.2 shows how financial penalties are assessed to Off-Dispatch and On-Dispatch/Non-Regulating units for causing other units to regulate.~~



~~**Figure 4.4.2: Penalties for Non-Regulation Providers**~~

~~The AAUCE for each non-regulating unit within each SCD interval will be calculated by averaging the following over that SCD interval:~~

$$\cancel{\left| RampSCD_{it} - G_{it} \right|}$$

~~Where:~~

~~$RampSCD_{it}$ = ramped SCD basepoint for generator *i* at time *t*; and~~

~~G_{it} = generation by generation *i* at time *t*.~~

~~RampSCD will be calculated by linearly interpolating the SCD basepoint from the preceding SCD interval and the SCD basepoint for the current SCD interval over the first five minutes of the current SCD interval. If the current SCD interval exceeds five minutes in length, the ramped SCD basepoint for all times five minutes or more after the beginning of the SCD interval will be equal to the SCD basepoint for that interval.~~

~~Also, in cases when the ISO NYISO NYISO has announced a reserve pickup, the term *$RampSCD_{it}$-G_{it}* will be set to zero for all times t at which G_{it}>$RampSCD_{it}$, if generator i is in an area affected by the reserve pickup.~~

~~Examples illustrating these procedures follow:~~

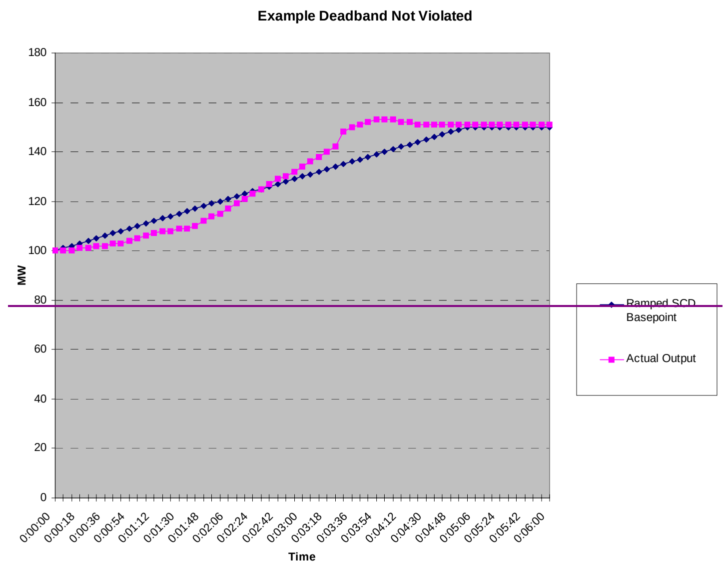
~~*Examples*~~

~~*Example 1*~~

~~**An On-Dispatch Unit Does Not Violate the Deviation Tolerance.**~~

~~The unit is a 600 MW (OpCap) unit that had a last basepoint and actual output of 100 MW. The new basepoint received at the top of the hour is 150 MW. Note that if the ISO NYISO NYISO regulation performance index is perfect at 1.0 then the deviation tolerance would be 6 MW. The chart below gives a visual indication of how a generating unit might be expected to respond. Although the information on unit control error is not explicitly shown, the average value was hand calculated at approximately 4.98 MW~~

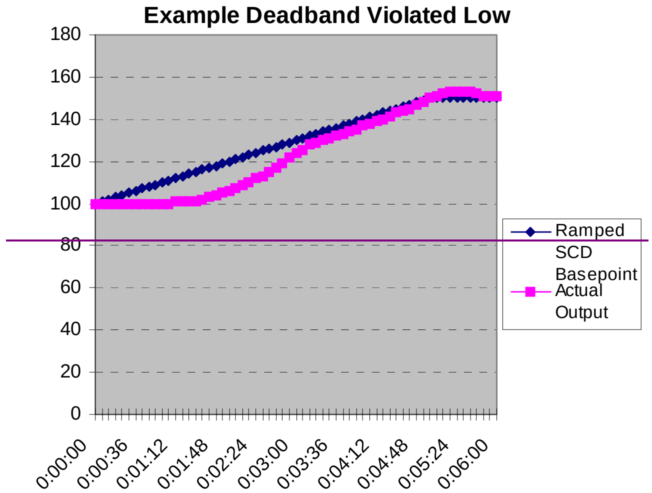
~~which is less than the deviation tolerance. Also, note that in this example the SCD interval was extended to 6 minutes. This demonstrates that after the first 5 minutes the ramped basepoint expected response of the unit remains flat at 150 MW until the next SCD execution. In this case no penalties would be incurred. Additionally, note that the average actual response is slightly more than the average ramped basepoint expected response so the unit does get paid for energy based on the average ramped basepoint expected response.~~



~~*Example 2*~~

~~**An On-Dispatch Unit which violates the Deviation Tolerance due to Under-Generation.**~~

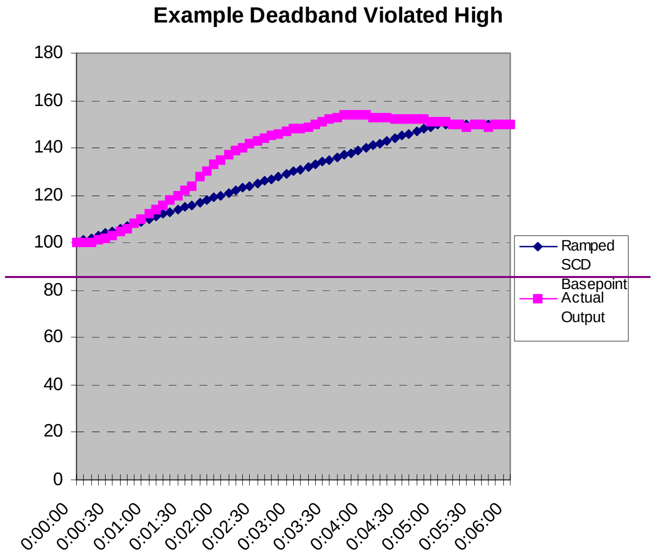
~~The unit is a 600 MW (OpCap) unit that had a last basepoint and actual output of 100 MW. The new basepoint received at the top of the hour is 150 MW. Note that if the ISO NYISO NYISO regulation performance index is perfect at 1.0 then the deviation tolerance would be 6 MW. The chart below gives a visual indication of how a generating unit might be expected to respond when under-generating. Although the information on unit control error is not explicitly shown, the average value was hand calculated at approximately 6.38 MW, which is greater than the deviation tolerance. Also, note that in this example the SCD interval was extended to 6 minutes. This demonstrates that after the first 5 minutes the ramped basepoint expected response of the unit remains flat at 150 MW until the next SCD execution. In this case the unit would get paid for its average actual energy output, because its average actual output is less than the average ramped SCD basepoint sent to that unit. The unit would be charged the real-time price of regulation multiplied by 0.38 MW, since this is the amount by which the unit's average absolute unit control error exceeded the deviation tolerance.~~



~~*Example 3*~~

~~**An On-Dispatch Unit Violates the Deviation Tolerance due to Over-Generation.**~~

~~The unit is a 600 MW (OpCap) unit that had a last basepoint and actual output of 100 MW. The new basepoint received at the top of the hour is 150 MW. Note that if the ISO NYISO NYISO regulation performance index is perfect at 1.0 then the deviation tolerance would be 6 MW. The chart below gives a visual indication of how a generating unit might be expected to respond when over-generating. Although the information on unit control error is not explicitly shown, the average value was hand calculated at approximately 8.1 MW, which is greater than the deviation tolerance. Also, note that in this example the SCD interval was extended to 6 minutes. This demonstrates that after the first 5 minutes the expected response of the unit remains flat at 150 MW until the next SCD execution. In this case the unit would get paid for its expected energy output, because its average actual output is greater than the average ramped SCD basepoint sent to that unit. The unit would be charged the real-time price of regulation multiplied by 2.1 MW, since this is the amount by which the unit's control error exceeded the deviation tolerance.~~



4.5 Regulation Service Settlements – Day-Ahead Market

4.5.1 Calculation of Day-Ahead Market Clearing Prices

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

~~As a result, t~~The Shadow Price ~~shall include~~ takes account of the Day-Ahead Regulation Service Bid of the marginal Resource selected to provide Regulation Service (or the applicable price on the Regulation Service Demand Curve during shortage conditions), plus any margins on the sale of Energy or Operating Reserves in the Day-Ahead Market that th~~at~~e Resource would forego if scheduling it to provide additional Regulation Service would lead to it being scheduled to provide less Energy or Operating Reserves. The Shadow Price~~s~~ ~~shall~~ also takes account of the Regulation Service Demand Curves described in Section 4.8 of this Manual, which will ensure that Regulation Service is not scheduled by SCUC at a cost greater than the Demand Curve indicates should be paid.

Each Supplier that is scheduled Day-Ahead to provide Regulation Service ~~shall be~~is paid the Day-Ahead Market clearing price in each hour, multiplied by the amount of Regulation Service that it is scheduled to provide ~~induring~~ for that hour.

4.5.2 Other Day-Ahead Payments

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

No payments shall be made to any Supplier providing Regulation Service in excess of the amount of Regulation Service scheduled by the NYISO in the Day-Ahead Market, except to the extent that a Supplier is directed to provide the excess amount by the NYISO.

4.6 Regulation Service Settlements – Real-Time Markets

4.6.1 Calculation of Real-Time Market Clearing Prices

The NYISO shall calculate a Real-Time Market clearing price for Regulation Service for every RTD interval, except as noted in Section 4.10 of this Manual. ~~Except when the circumstances described below in Section 4.6.2 apply~~Normally, the Real-Time Market clearing price for each interval shall equal the real-time Shadow Price for the NYISO's Regulation Service constraint for that RTD interval. ~~, which shall be established under the NYISO Procedures. Real-Time Shadow Prices will be calculated by the NYISO's RTD.~~Calculation of the Real-Time Market Clearing Price (MCP) during EDRP/SCR events is set forth in Section 4.6.2.

~~Each~~ The Real-Time ~~Shadow~~MCP ~~Price~~ ~~in~~for each RTD interval shall equal ~~the marginal Bid cost of scheduling Resources to provide additional Regulation Service in that interval, including any impact on the Bid Production Cost of procuring Energy or Operating Reserves that would result from procuring an increment of Regulation Service in that interval,~~ the Real-Time Shadow Price for the NYISO's Regulation Service constraint for that interval, as ~~calculated during the third RTD pass~~ described in Attachment B to the NYISO Services Tariff, and Attachment J to the NYISO OATT.

~~As a result, t~~The Shadow Price ~~shall include~~takes account of the Real-Time Regulation Service Bid of the marginal Resource selected to provide Regulation Service (or the applicable price on the Regulation Service Demand Curve during shortage conditions), plus any margins on the sale of Energy or Operating Reserves in the Real-Time Market that the Resource would forego if scheduling it to provide additional Regulation Service would lead to it being scheduled to provide less Energy or Regulation~~.~~. The Shadow Price~~s~~ ~~shall~~ also take~~s~~ account of the Regulation Service Demand Curves described in Section 4.8 of this Manual, which will ensure that Regulation Service is not scheduled by RTC at a cost greater than the Demand Curve indicates should be paid.

Each supplier that is scheduled in Real-Time to provide Regulation Service is paid the Real-Time MCP, for each RTD interval multiplied by the amount of Regulation Service that it is scheduled to provide during that interval.

4.6.2 Calculation of Real-Time Market Clearing Prices for Regulation Service during EDRP/SCR Activations

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

Specifically, when either scarcity pricing rule is applicable, the real-time Regulation Service clearing price shall be set to the higher of:

1. The highest total Availability Bids and Lost Opportunity Cost of any Regulation Service provider scheduled by RTD
2. The Market clearing price calculated under Section 4.6.1 of this Manual.

4.6.3 Real-Time Regulation Service Balancing Payments

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

1. When the Supplier's real-time Regulation Service schedule is less than its Day-Ahead Regulation Service award, the Generator shall pay a charge for the imbalance equal to the product of:
   a. The Real-Time Market clearing price for Regulation Service
   b. The difference between the Generator's Day-Ahead Regulation Service schedule and its real-time Regulation Service schedule ~~(subject to possible adjustments pursuant to Section 4.6.5 of the Manual).~~
2. When the Generator's real-time Regulation Service schedule is greater than its Day-Ahead Regulation Service schedule, the NYISO shall pay the Generator an amount to compensate it for the imbalance equal to the product of:
   a. The Real-Time Market clearing price for Regulation Service
   b. The difference between the Generator's Day-Ahead Regulation Service schedule and its real-time Regulation Service schedule ~~(subject to possible adjustments pursuant to Section 4.6.5 of this Manual).~~

4.6.4 Other Real-Time Regulation Service Payments

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

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

Finally, whenever a Generator's real-time Regulation Service schedule is reduced by the NYISO to a level lower than its Day-Ahead schedule for that product, the Generator's Day-Ahead Margin shall be protected after accounting for any margin associated with other products that the Generator is scheduled to provide in real-time. The rules governing the calculation of these Day-Ahead Margin Assurance Payments are set forth in Attachment J to the NYISO Services Tariff. In addition, Attachment D of this Manual provides additional information on performance-based adjustments to regulation service payments.

~~Performance-Based Adjustments to Regulation Service Payments~~

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

$$TotalPayment = \sum_i (TotalPayment_i * (s_i / 3600))$$

~~Where:~~

$$Total\ Payment_i = ((DAMCPreg_i * DARcap_i) + ((RTRcap_i * K_{Pi}) - DARcap_i) * RTMCPreg_i)$$

- ~~DAMCP*reg*~~$_i$ ~~is the applicable market clearing price for Regulation Service (in \$/MW), in the Day-Ahead Market as established by the NYISO pursuant to Section 4.5.1 of this Manual for the hour that includes RTD interval *i*~~
- ~~DAR*cap*~~$_i$ ~~is the Regulation Service Capability (in MW) offered by the Generator and selected by the NYISO in the Day-Ahead Market in the hour that includes RTD interval *i*~~
- ~~RTMCP*reg*~~$_i$ ~~is the applicable market clearing price for Regulation Service (in MW), in the Real-Time Market as established by the NYISO pursuant to Section 4.6.1 of this Manual in RTD interval *i*~~
- ~~RTR*cap*~~$_i$ ~~is the Regulation Service Capability (in MW) offered by the Generator and selected by the NYISO in the Real-Time Market in RTD interval *i*~~
- ~~s_i is the number of seconds in interval i~~
- ~~K_{Pi} is a factor, with a value between 0.0 and 1.0 inclusive, derived from each Generator's Regulation Service performance, as measured by the~~

~~performance indices set forth in the NYISO Procedures, and determined pursuant to the following equation:~~

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

~~Where:~~

- ~~PI is the Generator's performance index; and~~
- ~~PSF is the payment scaling factor, established pursuant to NYISO Procedures.~~

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

4.7 Energy Settlement Rules for Generators Providing Regulation Service

4.7.1 Energy Settlements

For any interval in which a Generator that is providing Regulation Service receives an AGC Base Point Signal that is different than its RTD Base Point Signal, the Generator shall receive a settlement payment for Energy consistent with a real-time Energy injection equal to the lower of its actual generation or its AGC Base Point Signal.

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

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

$$p_1 = \text{RTDBasePointSignal}$$

$$p_2 = \max\left[\text{RTDBasePointSignal}, \min\left(\text{AGCBasePointSignal}, \text{ActualOutput}\right)\right]$$

$$\text{Payment/Charge} = \left(\frac{s}{3600}\right) \times \int_{p_1}^{p_2} \left(\text{Bid(p)} - \text{LBMP}\right)dp$$

$$\cancel{Payment/Charge = \int_{RTDBasePoint\,Signal}^{\max(RTDBasePoint\,Signal,\min(AGCBasePoint\,Signal,ActualPOutput))} \left[Bid - LBMP\right] * s/3600}$$

Where:

- s is the number of seconds in the RTD interval;

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

4.7.3 Additional Charges/Payments When AGC Base Point Signals are Lower than RTD Base Point Signals

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

$$\cancel{Payment/Charge = \int_{\min(RTDBasePoint\,Signal,\max(AGCBaseSignal,ActualOutput))}^{RTDBasePoint\,Signal} -\left[Bid - LBMP\right] * s/3600}$$

RTDBasePointSignal

~~Payment/Charge= ∫-[Bid – LBMP] *s/3600~~

min(RTDBasePointSignal, max(AGCBaseSignal,Actual Output))

$$p_1 = \min\left[\text{RTDBasePointSignal}, \max\left(\text{AGCBasePointSignal}, \text{ActualOutput}\right)\right]$$

$$p_2 = \text{RTDBasePointSignal}$$

$$\text{Payment/Charge} = \left(\frac{s}{3600}\right) \times \int_{p_1}^{p_2} \left(\text{Bid(p)} - \text{LBMP}\right)dp$$

Where:

- *s* is the number of seconds in the RTD interval;

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

4.8 Regulation Service Demand Curve

The NYISO shall establish a Regulation Demand Curve that will apply to both the Day-Ahead and ~~real-time~~Real-Time Regulation Service markets. The market clearing prices for Regulation Service calculated pursuant to Sections 4.5.1 and 4.6.1 of this Manual shall take account of the demand curve established in this Section so that Regulation Service is not purchased at a cost higher than the demand curve indicates should be paid in the relevant market.

The NYISO shall establish a target level of Regulation Service for each hour, which will be the number of MW of Regulation Service that the NYISO would seek to maintain in that hour if cost were not a consideration. The NYISO will then define a Regulation Service demand curve for that hour as follows:

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

2. For quantities of Regulation Service that are less than equal to the target level of Regulation Service but that exceed the target level of Regulation Service minus 25 MW, the price on the Regulation Service demand curve shall be $250/MW.

3. For all other quantities, the price on the Regulation Service demand curve shall be $0/MW. However, the NYISO shall not schedule more Regulation Service than the target level for the requirement for that hour.

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

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

Not later than 90 days after the implementation of the Regulation Service Demand Curve, the NYISO, in consultation with its Market Advisor, shall conduct an initial review in accordance with the NYISO Procedures. The scope of the review shall include, but not be limited to, an analysis of whether the Regulation Service Demand Curve should be adjusted upward or downward in order to optimize the economic efficiency of any, or all, of the NYISO-Administered Markets. The NYISO and the Market Advisor shall perform additional quarterly reviews, subject to the same scope requirement, during the remainder of the first year that this Section 4.8 is in effect. After the first year, the NYISO and the Market Advisor shall perform periodic reviews, subject to the same scope requirement.

4.9 Reinstating Performance Charges

The NYISO will monitor, on a ~~real-time~~Real-Time hourly or daily basis, as appropriate, its compliance with the standards established by NERC and NPCC and with the standards of Good Utility Practice for Control Performance, Area Control Area, Disturbance Control Standards, Reserve Pickup Performance, and System Security. Should it appear to the NYISO that degradation in performance threatens compliance with one or more of the established standards for these criteria or compromises reliability, and that reinstating the performance charges that were originally part of the NYISO's market design, would assist in improving compliance with established standards for these criteria, or would assist in re-establishing reliability, the NYISO may require Suppliers of Regulation Service, as well as Suppliers not providing Regulation Service, to pay a performance charge.

Any reinstatement of Regulation penalties pursuant to this Section shall not override previous Commission-approved settlement agreements that exempt a particular unit from such penalties. The NYISO shall provide notice of its decision to reinstate performance charges to the Commission, to each Customer and to the Operating Committee and the Business Issues Committee no less than seven days before it re-institutes the performance charges.

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

Performance Charge = Energy Deviation ∗ MCPreg ∗ (Length of Interval/60 minutes)

Where:

- Energy Deviation (in MW) is the absolute difference between the actual Energy supplied by the Supplier and the Energy required by the AGC Base Point Signals, whether positive or negative, averaged over each RTD interval; and
- MCP_{reg} is the Market Clearing Price ($/MW), which applies to the RTD interval for this Service in the Real-Time Market or the Day-Ahead Market, if appropriate.

The method used by the NYISO to calculate the Energy Deviation will permit Suppliers a certain period of time to respond to AGC Base Point Signals. Initially this time period will be 30 seconds, although the NYISO will have the authority to change its length. If the Supplier's output at any point in time is between the largest and the smallest of the AGC Base Points sent to that Supplier within the preceding 30 seconds (or such other time period length as the NYISO may define), the Supplier's Energy Deviation at that point in time will be zero.

Otherwise, the Supplier may have a positive Energy Deviation. However, in cases in which responding to the AGC Base Point within that time period would require a Supplier to change output at a rate exceeding the amount of Regulation it has been scheduled to provide, the Supplier will have a zero Energy Deviation if it changes output at the rate equal to the amount of Regulation it is scheduled to provide.

4.10 Temporary Suspension of Regulation Service Markets During Reserve Pick-Up

During any period in which the NYISO has activated RTD-CAM software and has called for a "large event" or "small event" reserve or maximum generation pick-up, as described in Section 4.4.4(A) of the NYISO Services Tariff, the NYISO ~~s~~will suspend Generators' obligation to follow the AGC Base Point Signals sent to Regulation Service providers and will suspend the ~~real-time~~Real-Time Regulation Service market. The NYISO will not procure any Regulation Service and will establish a ~~real-time~~Real-Time Regulation Service Market clearing price of zero for settlement and balancing purposes. The NYISO will resume sending AGC Base Point Signals and restore the ~~real-time~~Real-Time Regulation Service market as soon as possible after the end of the reserve or maximum generation pickup.

4.11 Charges Applicable to Suppliers That Are Not Providing Regulation Service

4.11.1 Persistent ~~Undergeneration~~Under-generation Charges

An Energy Supplier that is not providing Regulation Service and that persistently operates at a level below its schedule shall pay a persistent ~~undergeneration~~under-generation charge to the NYISO, unless its operation is within a tolerance described below. Persistent ~~undergeneration~~under-generation charges shall be calculated as follows:

Persistent under-generation charge = Energy Difference ∗ MCPreg ∗ Length of Interval/60 Minutes

Where:

Energy Difference in (MW) is determined by subtracting the actual Energy provided by the Supplier from its RTD Base Point for the dispatch interval. The Energy Difference shall be set at zero for any Energy Difference that is otherwise negative or that falls within a tolerance, set pursuant to NYISO Procedures, and which shall contain a steady-state and a dynamic component. The steady-state component shall be 3% of the Supplier's Normal Upper Operating Limit or Emergency Upper Operating Limit, as applicable, and the dynamic component shall be a time constant that shall initially be set at fifteen minutes; and

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

4.11.2 Restoration of Performance Charges

The persistent ~~undergeneration~~under-generation charges described in Section 4.11.1 above shall be suspended in the event that the NYISO re-institutes Regulation performance charges pursuant to Section 4.9 of this Manual. If the NYISO re-institutes performance charges then Suppliers that sell Energy through the LBMP Markets or that supply Bilateral Transactions that serve Load in the NYCA, but that do not provide Regulation Service, shall pay a performance charge to the NYISO as follows:

Performance Charge = Energy Difference ∗ MCPreg ∗ Length of Interval/60 minutes

Where:

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

MCPreg is the Market Clearing Price ($/MW), which applies to the interval for which Regulation Service was provided in the Real-Time Market, or, if appropriate, the Day-Ahead Market.

In cases in which the Energy Difference that would be calculated using the procedure described above is less than ~~the tolerance set forth in the NYISO Procedures~~3%, the NYISO shall set the Energy Difference for that interval equal to zero.

4.11.3 Exemptions

The following types of Generator shall not be subject to persistent ~~undergeneration~~under-generation charges, or, if they are restored by the NYISO, to performance charges:

1. Generators providing Energy under contracts (including PURPA contracts), executed and effective on or before November 18, 1999, in which the power purchaser does not control the operation of the supply source but would be responsible for payment of the persistent ~~undergeneration~~under-generation or performance charge

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

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

4. Capacity Limited Resources and Energy Limited Resources to the extent that their ~~real-time~~Real-Time Energy injections are equal to or greater than their bid-

in upper operating limits but are less than their Real-Time Scheduled Energy Injections.

Note: This exemption does not apply to points 1, 2, and 3 above, in an hour if the Generator or Resource has bid in that hour as ISO-Committed Flexible or Self-Committed Flexible.

4.12 Charges to Load Serving Entities

All LSEs taking service under the NYISO OATT pay a charge for this Service on all Bilateral Transactions and purchases in the LBMP Markets to serve Load located in the NYCA. The NYISO calculates the charge, for each hour, by summing:

1. ***Supplier Payment –*** the aggregate payments made by the NYISO to all Suppliers of this Service.
2. ***Supplier Charge –*** the aggregate of charges paid by all Regulation Providers.
3. ***Non-Regulating Generator Charge –*** the aggregate of charges paid by all Generators.

In any hour where the charges paid by Generators and Suppliers exceed the payments made to Suppliers of Regulation service:

1. The NYISO will not assess a charge against any LSE.
2. Additionally, the surplus will be applied to the following hour as an offset to subsequent payments.

Otherwise, these charges are allocated to each LSE in the NYCA in proportion to its load ratio share for that hour. Charges that are paid by LSEs for this Service are aggregated to render a monthly charge.

4.13 Regulation & Frequency Response Notification Procedures

The following procedures are for notifying suppliers in the event that they exhibit poor “Regulation and Frequency Response” performance.

In the initial LBMP implementation, these procedures will be performed at the end of each billing cycle.

NYISO Actions

The NYISO shall perform the following:

1. Notify the poor performing supplier via telephone or E-mail, upon determination by the NYISO that the supplier is exhibiting poor performance.
2. Notify the poor performing supplier that they are currently being penalized as described in the *NYISO Accounting and Billing Manual*, and that persistent non-compliance in accordance with this procedure will result in additional penalties

and that consistent or continued poor performance will result in the provider being removed from the bidders list.

Regulation Provider Actions

The poor performer shall acknowledge the NYISO notification and report their expectation of the time they will be able to return to normal performance. The provider shall also describe the cause of their poor performance.

~~4.7 Payment for Service~~

~~The NYISO makes the following settlement with Suppliers of Regulation service:~~

~~4.8 An hourly Availability payment for reserving capability to provide Regulation service~~

~~4.9 An Energy payment based on the amount of regulation provided~~

- ~~A financial penalty based on poor performance as measured against expectations~~

~~The cost of regulation services, net of regulation penalties, is recovered through a charge assessed to Load Serving Entities (LSEs).~~

~~4.5.1. Determination of Day-Ahead and Supplemental Market Clearing Prices~~

~~The NYISO determines a Market Clearing Price (MCP) to be paid to Suppliers for Generator availability (in MW) reserved to provide this service in the Day-Ahead and Supplemental Markets.~~

~~The NYISO stacks Bids submitted by qualified Suppliers from the lowest Bid ($/MW) to the highest bid, with due consideration for locational regulation requirements (upstate vs. downstate). The NYISO selects Bids to provide this Service starting with the lowest Bid. The Bid associated with the last Supplier selected to supply Regulation service sets the single state wide MCP. All Suppliers selected in the same market (i.e., Day-Ahead or Real-Time) receive an Availability payment calculated with the corresponding MCP.~~

~~The NYISO applies the revenues from the Supplier charge and Generator charge to reduce the charge paid for Regulation service by the LSEs.~~

~~4.9.1 Energy Payments to Regulation Providers~~

~~For the purposes of calculating the real-time~~Real-Time ~~energy payment received by a regulation provider, it is helpful to define a variable, Z, which is set equal to AAGC - (RampedSCD-AAGC), where AAGC is the average AGC signal sent to that unit, and RampedSCD is the average ramped SCD base point sent to that unit over an SCD interval.~~

~~If the AAGC for a unit over an SCD interval is less than the RampedSCD for that unit over that SCD interval, then the real-time~~Real-Time ~~energy payment that units receives (or makes, if the payment is negative) for that SCD interval will be calculated as follows:~~

~~4.9.2 If the unit's average actual output for that SCD interval is less than Z, then the real-time~~Real-Time ~~energy payment will be equal to the unit's average actual output minus the unit's day-ahead energy schedule for that SCD interval, multiplied by the real-time~~Real-Time ~~LBMP for that SCD interval.~~

~~4.9.3~~

- ~~If the unit's average actual output for that SCD interval is greater than or equal to Z, but is less than or equal to AAGC, then the real-time~~Real-Time ~~energy payment will be equal to Z plus twice the difference between the unit's average actual output and Z minus the unit's day-ahead energy schedule for that SCD interval, multiplied by the real-time~~Real-Time ~~LBMP for that SCD interval.~~
- ~~If the unit's average actual output for that SCD interval is greater than AAGC, then the real-time~~Real-Time ~~energy payment will be equal to the RampedSCD for that unit in that SCD interval, minus the unit's day-ahead energy schedule for that SCD interval, multiplied by the real-time~~Real-Time ~~LBMP for that SCD interval.~~

~~**Otherwise:**~~

- ~~If the unit's average actual output for that SCD interval is less than or equal to AAGC, then that unit's real-time~~Real-Time ~~energy payment will be equal to the unit's average actual output minus the unit's day-ahead energy schedule for that SCD interval, multiplied by the real-time~~Real-Time ~~LBMP for that SCD interval.~~
- ~~If the unit's average actual output for that SCD interval is greater than AAGC, then that unit's real-time~~Real-Time ~~energy payment will be equal to AAGC minus the unit's day-ahead energy schedule for that SCD interval, multiplied by the real-time~~Real-Time ~~LBMP for that SCD interval.~~

~~4.5.3. Charges to Load Serving Entities~~

~~All LSEs taking service under the ISO NYISO NYISO OATT pay a charge for this Service on all Bilateral Transactions and purchases in the LBMP Markets to serve Load located in the NYCA. The NYISO calculates the charge, for each hour, by summing:~~

~~Supplier Payment — the aggregate payments made by the NYISO to all Suppliers of this Service.~~

~~Supplier Charge — the aggregate of charges paid by all Regulation Providers.~~

- ~~Non-Regulating Generator charge — the aggregate of charges paid by all Generators.~~

~~In any hour where the charges paid by Generators and Suppliers exceed the payments made to Suppliers of Regulation service:~~

- ~~The NYISO will not assess a charge against any LSE~~
- ~~Additionally, the surplus will be applied to the following hour as an offset to subsequent payments.~~

~~Otherwise, these charges are allocated to each LSE in the NYCA in proportion to its load ratio share for that hour. Charges that are paid by LSEs for this Service are aggregated to render a monthly charge.~~

~~4.10 Regulation & Frequency Response Procedures~~

~~The following procedures are for notifying suppliers in the event that they exhibit poor Regulation & Frequency Response performance.~~
~~In the initial LBMP implementation, these procedures will be performed at the end of each billing cycle.~~

~~NYISO Actions~~

~~The NYISO shall perform the following:~~

~~1) Notify the poor performing supplier via telephone or E-mail, upon determination by the NYISO that the supplier is exhibiting poor performance.~~

~~2) Notify the poor performing supplier that they are currently being penalized as described in the *NYISO Manual for Accounting & Billing* and that persistent non-compliance in accordance with this procedure will result in additional penalties and that consistent or continued poor performance will result in the provider being removed from the bidders list.~~

~~Regulation Provider Actions~~

~~The poor performer shall acknowledge the NYISO notification and report their expectation of the time they will be able to return to normal performance. The provider shall also describe the cause of their poor performance.~~

5. ENERGY IMBALANCE SERVICE

This section describes the energy imbalance service.

5.1 Description

Energy imbalance service falls into the following categories:

- ***Internal Energy Imbalance under the NYISO Services Tariff*** — All internal Energy imbalances for Transmission Customers taking service under the ~~ISO~~NYISO Services Tariff are addressed through the Real-Time Market and through the Real-Time Settlement process. All scheduled withdrawals and injections, including deviations from Bilateral Transaction schedules by Transmission Customers taking service under the ~~ISO~~NYISO Services Tariff, are ~~also~~ subject to the Real-Time Settlement. Refer to the *NYISO Manual for Accounting & Billing* for the description of charges associated with internal energy imbalances. Generators, LSEs and Transmission Customers with imbalances may also be subject to charges for Regulation and Frequency Response Service.
- ***Internal Energy Imbalance Under the OATT*** — All internal energy imbalances for Transmission Customers taking service under the ~~ISO~~NYISO OATT and not under the NYISO Services Tariff shall, when the Transmission Customer's actual energy withdrawals are less than its scheduled energy delivery, pay to the NYISO an amount equal to the greater of 150% of the ~~real-time~~Real-Time LBMP at the point of delivery or $100/Mwh. If the Transmission Customer's actual energy delivery exceeds its actual energy withdrawals, it will not be paid for the excess energy.
- ***External Energy Imbalance*** — External energy imbalance refers to the mismatch between scheduled and actual flows between the NY Control Area and other Control Areas. Inadvertent energy accounting is implemented according to existing NERC guidelines. Monthly internal/external meter corrections are also accounted for. Any increase or decrease in costs resulting from pay back of accumulated inadvertent interchange is included in the NYISO Scheduling, System Control, and Dispatch Service Charge (see Section 2 of this ~~manual~~Manual).

The NYISO is responsible for providing this service.

5.2 External Imbalances

The NYISO performs the following for External inadvertent interchange:

- accurately accounts for inadvertent Energy interchange, through daily schedule verification and the use of reliable metering equipment.
- minimizes unintentional inadvertent accumulation in accordance with NERC and NPCC policies.
- minimizes accumulated inadvertent Energy balances in accordance with NERC and NPCC policies.

The NYISO reduces accumulated External inadvertent Energy balances by one or both of the following methods:

1~~)~~) scheduling interchange payback with another Control Area as an interchange schedule between Control Areas.

2~~)~~) unilaterally offsetting the tie-line interchange schedule when such action will assist in correcting an existing time error.

External inadvertent interchange accumulated during On-Peak hours is paid back during On-Peak hours. Inadvertent interchange accumulated during Off-Peak hours is paid back during Off-Peak hours. In either case, payback is made with Energy "in-kind."

The Energy Imbalance consists of calculations and inadvertent interchange reports that are produced on ~~a~~an hourly, daily, and monthly basis. The *NYISO Manual for Accounting & Billing* gives a detailed description.

The payback process for inadvertent interchange between the NY Control Area and its neighboring control areas is covered in the *NYISO Manual for Transmission & Dispatching Operations*.

5.3 Monthly Meter Reading Adjustments

This subsection summarizes the meter reading adjustment process. Refer to the *NYISO Manual for Accounting & Billing* for a detailed description of the monthly meter reading adjustment.

5.3.1 Facilities Internal to the New York Control Area

The NYISO develops rules and procedures to implement adjustments to meter readings to reflect the differences between the integrated instantaneous metering data utilized by the NYISO for ~~SCD~~ RTD and actual data for internal facilities as recorded by billing metering.

5.3.2 Facilities on Boundaries with Neighboring Control Areas

The correction required for external Inadvertent Energy Accounting facilities on Interfaces between the New York Control Area and other Control Areas is done using Inadvertent Energy Accounting techniques established by the NYISO in accordance with NERC and other reliability criteria.

5.3.3 Adjustment Verification

The NYISO provides all necessary meter reading adjustment information required by the Transmission Owners to allow them to verify that meter reading adjustments were performed in accordance with the NYISO's Procedures.

6. OPERATING RESERVE SERVICE

6.1 Description

Operating Reserve service provides backup generation in the event that major Generating Resources trip off-line due to either a power system Contingency or equipment failure. In order for the New York Control Area (NYCA) to respond in a timely fashion, ~~most of~~ the reserves must be available from units within the ~~NY Control Area~~ NYCA and within specific regions, as required by the NYSRC.

Types of Operating Reserves:

- ~~Ten~~10-Minute Spinning Reserve — Operating Reserves provided by qualified Generators and qualified Interruptible/Dispatchable Load Resources located within the NYCA that are already synchronized to the NYS Power System and can respond to instructions from the NYISO to change output level within 10 minutes.
- ~~Ten~~10-Minute Non-Synchronized Reserve (10-Minute NSR) — Operating Reserves provided by Generators that can be started, synchronized, and loaded within 10 minutes. These reserves are carried on quick-start units, such as jet engine type gas turbines.
- ~~Thirty~~30-Minute Spinning Reserve - Operating Reserves provided by qualified Generators and qualified Interruptible/Dispatchable Load Resources located within the NYCA that are already synchronized to the NYS Power System and can respond to instructions from the NYISO to change output level within 30 minutes.~~provided by Generators and Interruptible/Dispatchable Load resources located within the NYCA that are already synchronized to the NYS Power System.~~
- 30-Minute Non-Synchronized Reserve (30-Minute NSR) – Operating reserves that can be provided by Generators that can be started, synchronized, and loaded within 30 minutes.
- Total 10-Minute Reserve — The sum of the 10-Minute Spinning Reserve and 10-Minute NSR. [NERC defines this as Contingency Reserve]
- Total 30-Minute Reserve – The sum of the 30-minute ~~Synchronized~~Spinning Reserve and 30-Minute NSR ~~Thirty-Minute Reserve — Operating Reserves~~ provided by Generators and interruptible/dispatchable load resources that respond~~s~~ to instructions to change output energy within 30 minutes.
- Total Operating Reserve — The sum of the total 10-minute reserve and the total 30-minute reserve. [The NERC definition of operating reserve includes regulation]

Minimum Operating Reserve Requirement:

- The NYCA's Operating Reserve requirements are:
  - Total Operating Reserve must be greater than or equal to one and one-half times the largest single Contingency (in MW) as defined by the NYISO;
  - Total 10-Minute Reserve must be greater than or equal to the largest single Contingency (in MW) as defined by the NYISO;
  - 10-Minute Spinning Reserve must be greater than or equal to one-half of the largest single Contingency (in MW) as defined by the NYISO.

- Figure 6.1-1 illustrates these requirements. At all times sufficient total 10-minute reserve is maintained to cover the energy loss due to the most severe Normal Transfer Criteria contingency within the NYCA or the energy loss caused by the cancellation of an interruptible export transaction (NYCA to neighboring control area) whichever is greater. In addition:
- The NYISO may establish additional categories of Operating Reserves if necessary to ensure reliability.
- The NYISO ensures that providers of Operating Reserves are properly located electrically so that transmission constraints resulting from either commitment or dispatch of units do not limit the ability to deliver Energy to Loads in the case of a Contingency.
- The NYISO ensures that Capacity counted toward meeting NYCA Operating Reserve requirements is not counted toward meeting Regulation and Frequency Response Service requirements.

~~The NYISO satisfies at least 50 percent of the total 10-minute reserve requirements with 10-Minute Spinning Reserve. If the NYISO satisfies all of the 10-minute reserve requirement through 10-Minute Spinning Reserve, it does not have to maintain 10-minute NSR. The NYISO may establish additional categories of Operating Reserves if necessary to ensure reliability.~~
~~At all times sufficient total 10-minute reserve is maintained to cover the energy loss due to the most severe Normal Transfer Criteria contingency within the NYCA or the energy loss caused by the cancellation of an interruptible export transaction (NYCA to neighboring control area) whichever is greater.~~
~~The NYISO ensures that providers of Operating Reserves are properly located electrically so that transmission constraints resulting from either commitment or dispatch of units do not limit the ability to deliver Energy to Loads in the case of a Contingency. The NYISO also ensures that Capacity counted toward meeting NYCA Operating Reserve requirements is not also counted toward meeting Regulation and Frequency Response Service requirements.~~
~~The NYCA's Operating Reserve requirement is equal to one and one-half times the largest single Contingency (in MW) as defined by the NYISO. Figure 6.1-1 illustrates these requirements. This figure needs to be replaced.~~

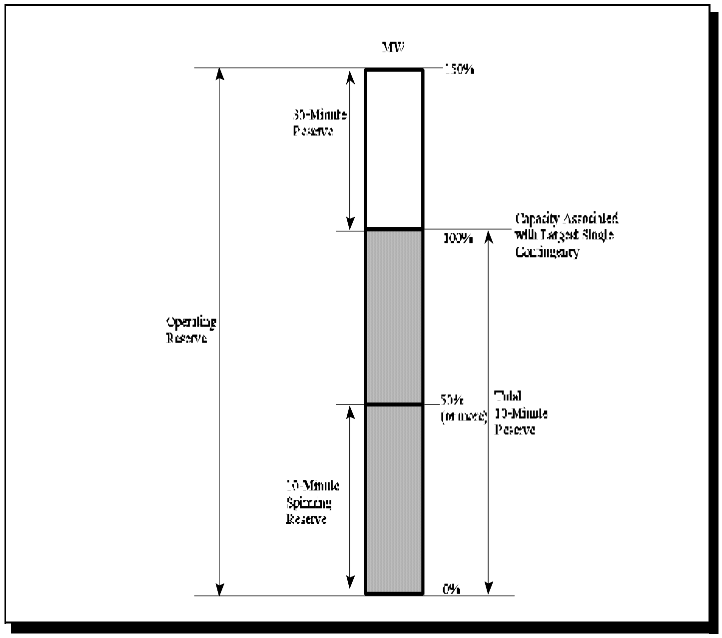
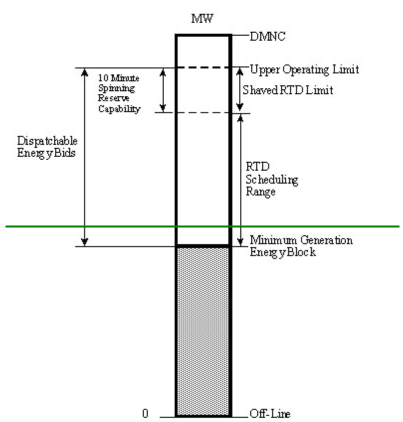


Figure 6.1-1: Operating Reserve Requirements

~~Figure 6.1-2 shows the relationship between the unit's 10-Minute Spinning Reserve~~,and ~~30-Minute Spinning Reserve schedules and the other operating parameters for a unit unit. RTD that has been scheduled to provide 10- or 30-Minute Spinning Reserve30-minute Synchronized Reserve, but not regulation. Security Constrained Dispatch (SCD) considers a range of operation in its determination of the RTDSCD basepoint that is bounded by the UOL and MinGen. reduced (shaved) by the amount of 10-Minute Spinning Reserve awarded.~~
~~RTD jointly optimizes the allocation of spinning reserves among units in order to satisfy the reserve requirementsSecurity Constrained Dispatch does not encroach on the unit's 10-Minute Spinning Reserve Capacity unless a reserve Pickup for the area in which that units is located~~.



~~**Figure 6.1-2: 10-Minute Spinning Reserve Schedules**~~

~~Figure 6.1-3 shows this relationship for a unit that is scheduled to provide both 10-Minute Spinning Reserve and Regulation. Security Constrained Dispatch does not encroach on the unit's Regulation Capacity.~~
~~Figure 6.1-3: 10-Minute Spinning Reserve & Regulation Schedules~~

6.2 General Responsibilities and Requirements

The NYISO is responsible for scheduling the Operating Reserve service. The NYISO ensures that Operating Reserve is properly geographically located so that transmission constraints do not limit the ability to deliver Operating Reserve. ~~The scheduling of these services involves a Day-Ahead commitment by the NYISO, a Real-Time Market evaluation, and then Real-Time Operation.~~ Reserve suppliers receive both a Day-Ahead and a Real-Time schedule. The Real-Time schedule may differ from the Day-Ahead schedule. Reserve suppliers must specify a Day-Ahead availability bid for each category of reserve. The Real-Time availability bid is automatically set to zero for each category of reserve and cannot be changed by a reserve supplier. Table 6.2 summarizes the ancillary service bidding for reserves and regulation.

Table 6.2-1: Ancillary Service Bid Representation

	Type of Unit	10-Minute Spinning	10-Minute Non-S~~pin~~ync	30-Minute Spinning	30-Minute Non-Sync~~pin~~	Regulation
On-Line	On-Dispatch (Flexible)	✓	N/A	✓	N/A	✓
On-Line	Off-Dispatch (Fixed)	N/A	N/A	N/A	N/A	N/A
Off-Line	Fast-Start (10-Minute Start)	✓	✓	✓	N/A	✓
Off-Line	Slow-Start (30-Minute Start)	✓	N/A	✓	✓	✓
	Availability Bids					
	Day-Ahead Market	Bid Permitted Note 1	Bid Permitted Note 1	Bid Permitted Note 1	Bid Permitted Note 1	Bid Permitted
	Real-Time Market	Bid by Definition Note 2	Bid by Definition Note 2	Bid by Definition Note 2	Bid by Definition Note 2	Bid Permitted
	MW Quantity	Note 3	Note 3	Note 3	Note 3	Bid MW/minute over 5 minutes

Note 1: If null bid is entered, the bid will not pass validation. A value must be entered, and it may be $0.

~~*Note 1:* If no Offer is entered, then a $0 offer is assumed.~~

Note 2: Offer is automatically set to $0.

Note 3: Reserve quantities will be defined by the unit's emergency ramp rate, but may also be limited by the size of the dispatchable range on the unit as defined by the applicable Emergency or Normal Upper Operating Limit.

6.2.1 NYISO Responsibilities

The NYISO shall procure on behalf of its Customers a sufficient quantity of Operating Reserve products to comply with the Reliability Rules and with other applicable reliability standards. ~~These quantities shall be established under Section 6.8 of this Manual.~~ To the extent that the NYISO enters into Operating Reserve sharing agreements with neighboring Control Areas its Operating Reserves requirements shall be adjusted accordingly.

The NYISO shall define requirements for Spinning Reserve, which may be met only by Suppliers that are eligible, under Section 6.2.2 of this Manual, to provide Spinning Reserve; 10-Minute Reserve, which may be met by Suppliers that are eligible to provide either Spinning Reserve or 10-Minute Non-Synchronized Reserve; and 30-Minute Reserve, which may be met by Suppliers that are eligible to provide any Operating Reserve product. The NYISO shall also define locational requirements for Spinning Reserve, 10-Minute Reserve, and 30-Minute Reserve located East of Central East and on Long Island as shown in Table 6.2-2.

Table 6.2-2: NYISO Locational Reserve Requirements

	New York CA	Eastern New York	Long Island
	A = most severe NYCA operating capability loss (1200MW)	B = largest Eastern unit generation (980MW)	C = largest Long Island unit gen. (180- 360MW)
10 Minute Spinning Reserve	½ A = 600MW (I)	½ B = 490MW (IV)	½ C = 90-180MW (VII)
10 Minute Total Reserve	A = 1200MW (II)	1200MW (V)	C = 180-360MW (VIII)
30 Minute Reserve	1½ A = 1800MW (III)	1½ B = 1470MW (VI)	1½ C =270-540MW (IX)

In addition to being subject to the preceding limitations on Suppliers that can meet each of these requirements, the requirements for Operating Reserve located East of Central East may only be met by eligible Suppliers that are located East of Central East, and requirements for Operating Reserve located on Long Island my only be met by eligible Suppliers located on Long Island. Each of these Operating Reserve requirements shall be defined consistent with the Reliability Rules and other applicable reliability standards. The NYISO shall select Suppliers of Operating Reserves products to meet these requirements, including the locational Operating Reserves requirements, as part of its overall co-optimization process.

The NYISO shall select Operating Reserves Suppliers that are properly located electrically so that all locational Operating Reserves requirements determined consistently with the requirements of Section 6.8 of this Manual are satisfied, and so that transmission constraints resulting from either the commitment or dispatch of

Generators do not limit the NYISO's ability to deliver Energy to Loads in the case of a Contingency. The NYISO will ensure that Suppliers that are compensated for using Capacity to provide one Operating Reserve product are not simultaneously compensated for providing another Operating Reserve product, or Regulation Service, using the same Capacity (consistent with the additive market clearing price calculation formulae in Sections 6.6.1 and 6.7.1 of this Manual.)

6.2.2 Supplier Eligibility Criteria

The NYISO shall enforce the following criteria, which define which types of Generators or Demand Side Resources are eligible to supply particular Operating Reserve products.

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

2. ***10-Minute Non-Synchronized Reserve*** – Off-line Generators that are capable of starting, synchronizing, and increasing their output level within ten minutes and that meet the criteria set forth in the NYISO Procedures, and, when the NYISO has the capability to support their participation, Demand Side Resources that are capable of reducing their Energy usage within ten minutes and that meet the criteria set forth in the NYISO Procedures, shall be eligible, provided that they are capable of providing Energy for at least thirty minutes, to supply 10-Minute Non-Synchronized Reserve.

3. ***30-Minute Reserve (spinning and non-synchronized)*** – (i) Generators that are ~~NY~~ISO~~-~~-Committed Flexible or Self-Committed Flexible and operating within the dispatchable portion of their operating range shall be eligible to supply synchronized 30-Minute Reserves; (ii) Off-line Generators that are capable of starting, synchronizing, and increasing their output level within thirty minutes and that meet the criteria set forth in the NYISO Procedures, and, when the NYISO has the capability to support their participation, Demand Side Resources that are capable of reducing their Energy usage within thirty minutes and that meet the criteria set forth in the NYISO Procedures, shall be eligible to supply non-synchronized 30-Minute Reserves.

4. ***Self-Committed Fixed and ~~NY~~ISO-Committed Fixed Generators*** – Shall not be eligible to provide any kind of Operation Reserve.

6.2.3 Other Supplier Requirements

All Suppliers of Operating Reserve must be located within the NYCA and must be under NYISO Operational Control. Each Supplier bidding to supply Operational Reserve or reduce demand must be able to provide Energy or reduce demand consistent with the Reliability Rules and the NYISO Procedures when called upon by the NYISO. All Suppliers that are selected to provide Operating Reserve shall ensure that their Resources maintain and deliver the appropriate quantity of Energy, or reduce the appropriate quantity of demand, when called upon by the NYISO during any interval in which they have been selected.

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

6.3 General Day-Ahead Market Rules

6.3.1 Bidding and Bid Selection

Resources capable of providing Spinning Reserve, 10-Minute Non-Synchronized Reserve, and/or 30-Minute Reserve (spinning and non-synchronized) in the Day-Ahead commitment may submit Availability Bids for each hour of the upcoming day. If a Supplier offers Resources that are capable, based on their indicated commitment status, of providing Operating Reserves but does not submit an Availability Bid, its Day-Ahead bid will be rejected in its entirety. A supplier may resubmit a complete Day-Ahead Bid, provided that the new bid is timely. ~~assigned a Day-Ahead Availability bid of $0/MWh~~. The same rules shall apply to Demand Side Resources capable of providing 10-Minute Non-Synchronized Reserve and/or non-synchronized 30-Minute Reserve when the NYISO has the capability to support their participation in Operating Reserves market. Refer to Table 6.2-1.

The NYISO may schedule Suppliers that make themselves available to provide Operating Reserves up to the following maximum Operating Reserve levels:

1. For Spinning Reserves, the Resource's emergency response rate multiplied by ten.

2. For 10-Minute Non-Synchronized Reserves, or for non-synchronized 30-Minute Reserves, the Resource's UOL_N or UOL_E, whichever is applicable at the relevant time (the Resource may offer one product or the other depending on the time required for it to start-up and synchronize to the grid).

3. For synchronized 30-Minute Reserves, the Resource's emergency response rate multiplied by 20. This represents the amount of spinning reserve, above and beyond 10-minute spinning reserve, that the Resource could convert to energy within 30 minutes.

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

The NYISO shall select Operating Reserve Suppliers for each hour of the upcoming day through a co-optimized Day-Ahead commitment process that minimizes the total cost of Energy, Operating Reserves, and Regulation Service, using Bids submitted pursuant to Section 4.2 of, and Attachment D to, the NYISO Services Tariff. As part of the co-optimization process, the NYISO shall determine how much of each Operating Reserves product particular Suppliers will be required to provide in light of the Reliability Rules and other applicable reliability standards, including the locational Operating Reserves requirements specified above.

6.3.2 NYISO Notice Requirement

The NYISO shall notify each Operating Reserve Supplier that has been selected in the Day-Ahead Schedule of the amount of each Operating Reserve product that it has been scheduled to provide.

6.3.3 Responsibilities of Suppliers Scheduled to Provide Operating Reserves in the Day-Ahead Market

Suppliers that are scheduled Day-Ahead to provide Operating Reserves shall either provide Operating Reserve, or Energy, or, when the NYISO has the capability to support demand side participation, reduce demand in ~~real-time~~Real-Time when scheduled by the NYISO in all hours for which they have been selected to provide Operating Reserve and are physically capable of doing so. However, Suppliers that are scheduled Day-Ahead to provide Operating Reserves and have startup periods of two hours or less may advise the NYISO no later than three hours prior to the first hour of their Day-Ahead schedule that they will not be available to provide Operating Reserves or Energy in ~~real-time~~Real-Time under normal conditions. Such Suppliers will be required to settle their Day-Ahead schedule at ~~real-time~~Real-Time prices pursuant to Section 6.7.3 of this Manual. The only restriction on Suppliers' ability to exercise this option is that all Suppliers with Day-Ahead Operating Reserves schedules must make the scheduled amount of Capacity available to the NYISO for dispatch in the RTD if the NYISO initiates a Supplemental Resource Evaluation.

6.4 General Real-Time Market Rules

6.4.1 Bid Selection

The NYISO will automatically select Operating Reserves Suppliers in ~~real-time~~Real-Time from eligible Resources, and when the NYISO has the capability to support their participation, Demand Side Resources, that submit Real-Time Bids pursuant to Section 4.4 of, and Attachment D to, the NYISO Services Tariff. All Suppliers will automatically be assigned a ~~real-time~~Real-Time Operating Reserves Availability bid of $0/MW. The NYISO may schedule Suppliers that make themselves available to provide Operating Reserves up to the following maximum Operating Reserve levels:

1. For Spinning Reserves, the Resource's emergency response rate multiplied by ten.

2. For 10-Minute Non-Synchronized Reserves, or for non-synchronized 30-Minute Reserves, the Resource's UOL_N or UOL_E, whichever is applicable at the relevant time (the Resource may offer one product or the other depending on the time required for it to start-up and synchronize to the grid).

3. For synchronized 30-Minute Reserves, the Resource's emergency response rate multiplied by 30.

However, the sum of the amount of Energy, or, when the NYISO has the capability to support demand side participation, Demand Reduction, that each Resource is scheduled to provide, the amount of Regulation Service it is scheduled to provide, and the amount of each Operating ~~Reserves~~Reserves product it is scheduled to provide shall not exceed its UOL_N or UOL_E, whichever is applicable.

Suppliers will thus be selected ~~on the basis of~~based on their response rates, their applicable upper operating limit, and their Energy Bid (which will reflect their opportunity costs) through a co-optimized ~~real-time~~Real-Time commitment process that minimizes the total cost of Energy, Regulation Service, and Operating Reserves. As part of the process, the NYISO shall determine how much of each Operating Reserves product particular Suppliers will be required to provide in light of the Reliability Rules and other applicable reliability standards, including the locational Operating Reserves requirements specified above.

6.4.2 NYISO Notice Requirements

The NYISO shall notify each Supplier of Operating Reserve that has been selected by RTD of the amount of Operating Reserve that it must provide.

6.4.3 Obligation to Make Resources Available to Provide Operating Reserves

Any Resource that is eligible to supply Operating Reserves and that is made available to the NYISO for dispatch in Real-Time must also make itself available to provide Operating Reserves.

6.4.4 Activation of Operating Reserves

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

6.4.5 Performance Tracking and Supplier Disqualifications

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

6.5 Operating Reserve Settlements – General Rules

6.5.1 Establishing Locational Reserve Prices

Except as noted below, the NYISO shall calculate separate Day-Ahead Market and Real-Time Market prices for each of the three Operating Reserve products for each of three locations:

1. West of Central-East (West or Western)
2. East of Central-East Excluding Long Island (East or Eastern)
3. Long Island (L.I.).

The NYISO will thus calculate nine different locational Operating Reserve prices in both the Day-Ahead Market and the Real-Time Market. Day-Ahead locational reserve prices shall be calculated pursuant to Section 6.6 of this Manual. Real-Time locational reserve prices shall be calculated pursuant to Section 6.7 of this Manual.

6.5.2 Settlements Involving Suppliers of Operating Reserves Located on Long Island

Suppliers of Operating Reserves located on Long Island shall receive settlement payments as if they were providing Operating Reserves located in the East. The NYISO will calculate separate locational Long Island Operating Reserves prices but will not post them or use them for settlement purposes.

6.5.3 "Cascading" of Operating Reserves

The NYISO will deem Spinning Reserve to be the "highest quality" Operating Reserve, followed by 10-Minute Non-Synchronized Reserve and by 30-Minute Reserve (spinning and then non-synchronized). The NYISO shall substitute higher quality Operating Reserves in place of lower quality Operating Reserves, when doing so lowers the total as-bid cost, i.e., when the marginal cost for the higher quality Operating Reserve product is lower than the marginal cost for the lower quality Operating Reserve product, and the substitution of a higher quality for the lower quality product does not cause locational Operating Reserve requirements to be violated. To the extent, however, that reliability standards require the use of higher quality Operating Reserves, substitution cannot be made in the opposite direction.

The price of higher quality Operating Reserves will not be set at a price below the price of lower quality Operating Reserves in the same location. Thus, the price of Spinning Reserves will not be below the price for 10-Minute Non-Synchronized Reserves or 30-Minute Reserves and the clearing price for 10-Minute Non-Synchronized Reserves will not be below the clearing price for 30-Minute Reserves.

6.6 Operating Reserve Settlements – Day-Ahead Market

6.6.1 Calculation of Day-Ahead Market Clearing Prices

The NYISO shall calculate hourly Day-Ahead Market Clearing Prices for each Operating Reserve product at each location. Each Day-Ahead Market Clearing Price shall equal the sum of the relevant Day-Ahead locational Shadow Prices for that product in that hour, subject to the restriction described in Section 6.5.3 of this Manual.

The Day-Ahead Market Clearing Price for a particular Operating Reserve product in a particular location shall reflect the Shadow Prices associated with all of the NYISO-defined Operating Reserve requirements, including locational requirements, that a particular Operating Reserves product from a particular location may be used to satisfy in a given hour. The NYISO shall calculate Day-Ahead Market Clearing Prices using the following formulae:

~~Market Clearing Price for Western 30-Minute Reserves = SP1~~

~~Market Clearing Price for Western 10-Minute Non-Synchronized Reserves = SP1 + SP2~~

~~Market Clearing Price for Western Spinning Reserves = SP1 + SP2 + SP3~~

~~Market Clearing Price for Eastern 30-Minute Reserves = SP1 + SP4~~

~~Market Clearing Price for Eastern 10-Minute Non-Synchronized Reserves = SP1 + SP2 + SP4 + SP5~~

~~Market Clearing Price for Eastern Spinning Reserves = SP1 + SP2 + SP3 + SP4 + SP5 + SP6~~

~~Market Clearing Price for L.I. 30-Minute Reserves = SP1 + SP4 + SP7~~

~~Market Clearing Price for L.I. 10-Minute Non-Synchronized Reserves = SP1 + SP2 + SP4 + SP5 + SP7 + SP8~~

~~Market Clearing Price for L.I. Spinning Reserves = SP1 + SP2 + SP3 + SP4 + SP5 + SP6 + SP7 + SP8 + SP9~~

Market clearing price for Western 30-minute reserve	$MCP_{30}^{W} = SP_1$
Market clearing price for Western 10-minute non-synchronized reserve	$MCP_{10N}^{W} = SP_1 + SP_2$
Market clearing price for Western 10-minute spinning reserve	$MCP_{10S}^{W} = SP_1 + SP_2 + SP_3$
Market clearing price for Eastern 30-minute reserve	$MCP_{30}^{E} = SP_1 + SP_4$
Market clearing price for Eastern 10-minute non-synchronized reserve	$MCP_{10N}^{E} = SP_1 + SP_2 + SP_4 + SP_5$
Market clearing price for Eastern 10-minute spinning reserve	$MCP_{10S}^{E} = SP_1 + SP_2 + SP_3 + SP_4 + SP_5 + SP_6$
Market clearing price for Long Island 30-minute reserve	$MCP_{30}^{LI} = SP_1 + SP_4 + SP_7$
Market clearing price for Long Island 10-minute non-synchronized reserve	$MCP_{10N}^{LI} = SP_1 + SP_2 + SP_4 + SP_5 + SP_7 + SP_8$
Market clearing price for Long Island 10-minute spinning reserve	$MCP_{10S}^{LI} = SP_1 + SP_2 + SP_3 + SP_4 + SP_5 + SP_6 + SP_7 + SP_8$

Where:

SP_1 = Shadow Price for total 30-Minute Reserve requirement constraint for the hour

SP_2 = Shadow Price for total 10-Minute Reserve requirement constraint for the hour

SP_3 = Shadow Price for total Spinning Reserve requirement constraint for the hour

SP_4 = Shadow Price for Eastern or L.I. 30-Minute Reserve requirement constraint for the hour

SP_5 = Shadow Price for Eastern or L.I. 10-Minute Reserve requirement constraint for the hour

SP_6 = Shadow Price for Eastern or L.I. Spinning Reserve requirement constraint for the hour

SP_7 = Shadow Price for Long Island 30-Minute Reserve requirement constraint for the hour

SP_8 = Shadow Price for Long Island 10-Minute Reserve requirement constraint for the hour

SP_9 = Shadow Price for Long Island Spinning Reserve requirement constraint for the hour

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

As a result, the Shadow Price for each Operating Reserves requirement shall include the Day-Ahead Availability Bid of the marginal Resource selected to meet the requirement (or the applicable price on the Operating Reserve Demand Curve for that requirement during shortage conditions), plus any margins on the sale of Energy or Regulation Service in the Day-Ahead Market that that Resource would forego if scheduling it to provide additional Operating Reserve to meet that requirement would lead to it being scheduled to provide less Energy or Regulation Service.

Shadow Prices will also be consistent with the Operating Reserve Demand Curves described in Section 6.8 of this Manual, which will ensure that Operating Reserves are not scheduled by SCUC at a cost greater than the relevant Operating Reserve Demand Curve indicates should be paid. If more Operating Reserve of a particular quality than is needed is scheduled to meet a particular locational Operating Reserve requirement, the Shadow Price for that Operating Reserve requirement constraint shall be set at zero.

Each Supplier that is scheduled Day-Ahead to provide Operating Reserve shall be paid the applicable Day-Ahead Market Clearing Price, based on its location and the quality of Operating Reserve scheduled, multiplied by the amount of Operating Reserve that the Supplier is scheduled to provide in each hour.

6.6.2 Other Day-Ahead Payments

As is provided in Section 4.10 and Attachment C of the NYISO Services Tariff, the NYISO shall compensate each ~~NY~~ISO-Committed Flexible Resource providing Operating Reserves if its Bid Production Cost to provide the Energy and Ancillary Services it is scheduled to supply in the Day-Ahead Market, including start-up costs, minimum Load costs, and Availability Bids, exceeds the revenues it receives from the sale of Energy and Ancillary Services.

6.7 Operating Reserve Settlements – Real-Time Market

6.7.1 Calculation of Real-Time Market Clearing Prices

The NYISO shall calculate Real-Time Market clearing prices for each Operating Reserve product for each location in every interval. Except when the circumstances described below in Section 6.7.2 apply, each ~~real-time~~Real-Time market-clearing price shall equal the sum of the relevant ~~real-time~~Real-Time locational Shadow Prices for that product, subject to the restriction described in Section 6.5.3 of this Manual.

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

Market clearing price for Western 30-minute reserve	$MCP_{30}^{W} =$	SP_1
Market clearing price for Western 10-minute non-synchronized reserve	$MCP_{10N}^{W} =$	$SP_1 + SP_2$
Market clearing price for Western 10-minute spinning reserve	$MCP_{10S}^{W} =$	$SP_1 + SP_2 + SP_3$
Market clearing price for Eastern 30-minute reserve	$MCP_{30}^{E} =$	$SP_1 + SP_4$
Market clearing price for Eastern 10-minute non-synchronized reserve	$MCP_{10N}^{E} =$	$SP_1 + SP_2 + SP_4 + SP_5$
Market clearing price for Eastern 10-minute spinning reserve	$MCP_{10S}^{E} =$	$SP_1 + SP_2 + SP_3 + SP_4 + SP_5 + SP_6$
Market clearing price for Long Island 30-minute reserve	$MCP_{30}^{LI} =$	$SP_1 + SP_4 + SP_7$
Market clearing price for Long Island 10-minute non-synchronized reserve	$MCP_{10N}^{LI} =$	$SP_1 + SP_2 + SP_4 + SP_5 + SP_7 + SP_8$
Market clearing price for Long Island 10-minute spinning reserve	$MCP_{10S}^{LI} =$	$SP_1 + SP_2 + SP_3 + SP_4 + SP_5 + SP_6 + SP_7 + SP_8$

~~Market Clearing Price for Western 30-Minute Reserves = SP1~~

~~Market Clearing Price for Western 10-Minute-Non-Synchronized Reserves = SP1 + SP2~~

~~Market Clearing Price for Western Spinning Reserves = SP1 + SP2 + SP3~~

~~Market Clearing Price for Eastern 30-Minute Reserves = SP1 + SP4~~

~~Market Clearing Price for Eastern 10-Minute Non-Synchronized Reserves = SP1 + SP2 + SP4 + SP5~~

~~Market Clearing Price for Eastern Spinning Reserves = SP1 + SP2 + SP3 + SP4 + SP5 + SP6~~

~~Market Clearing Price for L.I. 30-Minute Reserves = SP1 + SP4 + SP7~~

~~Market Clearing Price for L.I. 10-Minute Non-Synchronized Reserves = SP1 + SP2 + SP4 + SP5 + SP7 + SP8~~

~~Market Clearing Price for L.I. Spinning Reserves = SP1 + SP2 + SP3 + SP4 + SP5 + SP6 + SP7 + SP8 + SP9~~

Where:

SP_1 = Shadow Price for total 30-Minute Reserve requirement constraint for the interval

SP_2 = Shadow Price for total 10-Minute Reserve requirement constraint for the interval

SP_3 = Shadow Price for total Spinning Reserve requirement constraint for the interval

SP_4 = Shadow Price for Eastern or L.I. 30-Minute Reserve requirement constraint for the interval

SP_5 = Shadow Price for Eastern or L.I. 10-Minute Reserve requirement constraint for the interval

SP_6 = Shadow Price for Eastern or L.I. Spinning Reserve requirement constraint for the interval

SP_7 = Shadow Price for Long Island 30-Minute Reserve requirement constraint for the interval

SP_8 = Shadow Price for Long Island 10-Minute Reserve requirement constraint for the interval

SP_9 = Shadow Price for Long Island Spinning Reserve requirement constraint for the interval

Real-time locational Shadow Prices will be calculated by the NYISO's RTD. Each Real-Time Shadow Price for each Operating Reserves requirement in each RTD interval shall equal the marginal Bid cost of scheduling Resources to provide additional Operating Reserves to meet that requirement in that interval, including any impact on the Bid Production Cost of procuring Energy or Regulation Service that would result from procuring an increment of Operating Reserve to meet the requirement in that interval, as calculated during the third RTD pass described in Attachment B to the NYISO Service Tariff, and Attachment J to the NYISO OATT.

As a result, the Shadow Price for each Operating Reserves requirement shall include the Real-Time Availability Bid of the marginal Resource selected to meet that requirement (or the applicable price on the Operating Reserve Demand Curve for that requirement during shortage conditions), plus any margins on the sale of Energy or Regulation Service in the Real-Time Market that that Resource would forego if scheduling it to provide additional Operating Reserve to meet that requirement would lead to it being scheduled to provide less Energy or Regulation Service.

Shadow Prices will also be consistent with the Operating Reserve Demand Curves described in Section 6.8 of this Manual, which will ensure that Operating Reserves are not scheduled by RTC at a cost greater than the relevant Operating Reserve Demand Curve indicates should be paid. If there is more Operating Reserve of the required quality than is needed to meet a particular locational Operating Reserve requirement then the Shadow Price for that Operating Reserve requirement constraint shall be zero.

Each Supplier that is scheduled in ~~real-time~~Real-Time to provide Operating Reserve shall be paid the applicable ~~real-time~~Real-Time Market clearing price, based on its location and the quality of Operating Reserve scheduled, multiplied by the amount of Operating Reserve that the Supplier is scheduled to provide in each interval.

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

Scarcity pricing rules A and B are invoked when SCR/EDRP resources are activated and, but for the SCR/EDRP resources, the NYCA would experience a shortage of reserve. Scarcity pricing rule A applies when, but for SCR/EDRP resources, the NYCA would experience a shortage of reserve. Scarcity pricing rule B applies when, but for SCR/EDRP resources, the eastern portion of the NYCA would experience a shortage of reserve.

Scarcity Pricing Rule "A"

During any interval in which the NYISO is using scarcity pricing rule "A" to calculate LBMPs under Section I.A.2.a of Attachment B to the NYISO Services Tariff, and Attachment J to the NYISO OATT, the ~~real-time~~Real-Time market clearing prices for some Operating Reserves products may be recalculated in light of the Lost Opportunity Costs of Resources that are scheduled to provide Spinning Reserves and ~~synchronized~~ 30-Minute Reserves in the manner described below. The NYISO shall also consider the Lost Opportunity Costs of Resources providing lower quality Operating Reserves to ensure that the requirements of Section 6.5.3 of this Manual are not violated. Specifically:

4. The Eastern Spinning Reserve market clearing price shall be higher of:
   a. The highest Lost Opportunity Cost of any provider of Spinning Reserves and ~~synchronized~~ 30-Minute Spinning Reserve that is scheduled by RTD and is not located on Long Island
   b. The original market clearing price calculated under Section 6.7.1 above.

5. The Eastern 10-Minute Non-Synchronized Reserve market clearing price shall be the higher of:
   a. The highest Lost Opportunity Cost of any provider of spinning~~synchronized~~ 30-Minute Reserve that is scheduled by RTD and is not located on Long Island
   b. The original market clearing price calculated under Section 6.7.1 above.

6. The Eastern 30-Minute Reserve market clearing price shall be the higher of:

a. The highest Lost Opportunity Cost of any provider of spinning~~synchronized~~ 30-Minute Reserve that is scheduled by RTD and is not located on Long Island
b. The original market clearing price calculated under Section 6.7.1 above.

7. The Western Spinning Reserve market clearing price shall be the higher of:

   a. The highest Lost Opportunity Cost of any provider of Western Spinning Reserve Western Spinning 30-Minute Reserves that is scheduled by RTD
   b. The original market clearing price calculated under Section 6.7.1 above.

8. The Western 10-Minute Non-Synchronized Reserve market clearing price shall be the higher of:

   a. The highest Lost Opportunity Cost of any provider of Western spinning~~synchronized~~ and 30-Minute Reserve that is scheduled by RTD; and
   b. The original market clearing price calculated under Section 6.7.1 above.

9. The Western 30-Minute Reserve market clearing price shall be the higher of:

   a. The highest Lost Opportunity Cost of any provider of Western spinning~~synchronized~~ and 30-Minute Reserves that is scheduled by RTD
   b. The original market clearing price calculated under Section 6.7.1 above.

Scarcity Pricing Rule "B"

During any interval in which the NYISO is using scarcity pricing rule "B" to calculate LBMPs under Section I.A.2.b of Attachment B to the NYISO Services Tariff, and Attachment J to the NYISO OATT, the ~~real-time~~Real-Time market clearing prices for some Operating Reserves products may be recalculated in light of the Lost Opportunity Costs of Resources scheduled to provide Spinning Reserves and 30-Minute Reserves in order to satisfy Eastern Operating Reserve requirements in the manner described below. The NYISO shall also consider the Lost Opportunity Costs of Resources providing lower quality Operating Reserves to ensure that the requirements of Section 6.5.3 of this Manual are not violated. Specifically:

1. The Eastern Spinning Reserve market clearing price shall be the higher of:

   a. The highest Lost Opportunity Cost of any provider of Eastern Spinning Reserve ~~or synchronized~~ and 30-Minute ~~Spinning~~ Reserve that is scheduled by RTD and is not located on Long Island
   b. The original market clearing price calculated under Section 6.7.1 above.

2. The Eastern 10-Minute Non-Synchronized Reserve market clearing price shall be the higher of:

   a. The highest Lost Opportunity Cost of any provider of Eastern spinning~~synchronized~~ and 30-Minute ~~Spinning~~ Reserve that is scheduled by RTD and is not located on Long Island
   b. The original market clearing price calculated under Section 6.7.1 above.

3. The Eastern 30-Minute Reserve market clearing price shall be the higher of:

a. The highest Lost Opportunity Cost of any provider of Eastern spinning and ~~synchronized~~ 30-Minute Reserve that is scheduled by RTD and is not located on Long Island
b. The original market clearing price calculated under Section 6.7.1 above.

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

6.7.3 Operating Reserve Balancing Payments

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

1. When the Supplier's ~~real-time~~Real-Time Operating Reserves schedule is less than its assigned Day-Ahead Operating Reserves schedule, the Supplier shall pay a charge for the imbalance equal to the product of:

    a. The Real-Time Market clearing price for the relevant Operating Reserves Product in the relevant location; and
    b. The difference between the Supplier's Day-Ahead and ~~real-time~~Real-Time Operating Reserves schedules.

2. When the Supplier's ~~real-time~~Real-Time Operating Reserves schedule is greater than its assigned Day-Ahead Operating Reserves schedule, the NYISO shall pay the Supplier an amount to compensate it for the imbalance equal to the product of:

    a. The Real-Time Market Clearing Price for the relevant Operating Reserve product in the relevant location; and
    b. The difference between the Supplier's Day-Ahead and ~~real-time~~Real-Time Operating Reserves schedules.

6.7.4 Other Real-Time Payments

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

As is provided in Section 4.10 and Attachment C of the NYISO Services Tariff, the NYISO shall compensate each ~~NY~~ISO~~-~~-Committed Flexible Supplier providing Operating Reserves if its Bid Production Cost to provide the Energy and Ancillary Services it is scheduled to supply in the Real-Time Market, including Minimum Generation Bid and Start-Up Bid costs, the revenues it receives from the sale of Energy and Ancillary Services. Any Supplier that provides Energy during a large event reserve pickup or a maximum generation event, as described in Sections 4.4.4(A) (1) and (2) of the NYISO Services Tariff shall be eligible for a Bid Production Cost guarantee payment calculated, under Attachment C, solely for the duration of the large event reserve pickup or maximum generation pickup.

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

6.8 Operating Reserve Demand Curves

The NYISO shall establish nine Operating Reserve Demand Curves, one for each Operating Reserves requirement. Specifically, there shall be a demand curve for:

1. Total Spinning Reserves
2. Eastern or Long Island Spinning Reserves
3. Long Island Spinning Reserves
4. Total 10-Minute Non-Synchronized Reserves
5. Eastern or Long Island 10-Minute Non-Synchronized Reserves
6. Long Island 10-Minute Non-Synchronized Reserves
7. Total 30-Minute Reserves
8. Eastern or Long Island 30-Minute Reserves
9. Long Island 30-Minute Reserves.

Each Operating Reserve Demand Curve will apply to both the Day-Ahead Market and the Real-Time Market for the relevant product and location.

~~The market clearing prices for Operating Reserves shall be calculated pursuant to Sections 6.6.1 and 6.7.1 of this Manual and in a manner consistent with the demand curves established in this Section so that Operating Reserves are not purchased at a cost higher than the relevant demand curve indicates should be paid.~~

The NYISO Procedures shall establish a target level for each Operating Reserves requirement for each hour, which will be the number of MW of Operating Reserves meeting that requirement that the NYISO would seek to maintain in that hour if cost were not a consideration. The NYISO will then define an Operating Reserves demand curve for that hour corresponding to each Operating Reserves requirement as follows:

1. ***Total Spinning Reserves*** – For quantities of Operating Reserves meeting the total Spinning Reserves requirement that are less than or equal to the target level for that requirement, the price on the total Spinning Reserves demand curve shall be \$500/MW. For all other quantities, the price on the total Spinning Reserves demand curve shall be \$0/MW.

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

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

4. ***Total 10-Minute Reserves*** – For quantities of Operating Reserves meeting the total 10-minute reserves requirement that are less than or equal to the target level for that requirement, the price on the total 10-minute reserves demand curve shall be $150/MW. For all other quantities, the price on the total 10-minute reserves demand curve shall be $0/MW.

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

6. ***Long Island 10-Minute Reserves*** – For quantities of Operating Reserves meeting the Long Island 10-minute reserves requirement that are less than or equal to the target level for that requirement, the price on the Long Island 10-minute reserves demand curve shall be $25/MW. For all other quantities, the price on the Long Island 10-minute reserves demand curve shall be $0/MW.

7. ***Total 30-Minute Reserves*** – For quantities of Operating Reserves meeting the total 30-Minute Reserves requirement that are less than or equal to the target level for that requirement minus 400 MW, the price on the total 30-Minute Reserves demand curve shall be $200/MW. For quantities of Operating Reserves meeting the total 30-Minute Reserves requirement that are less than or equal to the target level for that requirement minus 200 MW but that exceed the target level for that requirement minus 400 MW, the price on the total 30-Minute Reserves demand curve shall be $100/MW.

   For quantities of Operating Reserves meeting the total 30-Minute Reserves requirement that are less than or equal to the target level for that requirement but that exceed the target level for that requirement minus 200 MW, the price on the total 30-Minute Reserves demand curve shall be $50/MW. For all other quantities, the price on the total 30-Minute Reserves demand curve shall be $0/MW. However, the NYISO will not schedule more total 30-Minute Reserves than the level defined by the requirement for that hour.

8. ***Eastern or Long Island 30-Minute Reserves*** – For quantities of Operating Reserves meeting the Eastern or Long Island 30-Minute Reserves requirement

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

9. ***Long Island 30-Minute Reserves*** – For quantities of Operating Reserves meeting the Long Island 30-Minute Reserves requirement that are less than or equal to the target level for that requirement, the price on the Long Island 30-Minute Reserves demand curve shall be $300/MW. For all other quantities, the price on the Long Island 30-Minute Reserves demand curve shall be $0/MW.

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

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

Not later than 90 days after the implementation of the Operating Reserve Demand Curves, the NYISO, in consultation with its Market Advisor, shall conduct an initial interview of them in accordance with the NYISO Procedures. The scope of the review shall include, but not be limited to, an analysis of whether any Operating Reserve Demand Curve should be adjusted upward or downward in order to optimize the economic efficiency of any, or all, of the NYISO-Administered Markets. The NYISO and the Market Advisor shall perform additional quarterly reviews, subject to the same scope requirement, during the remainder of the first year that this Section 6.8 is in effect. After the first year, the NYISO and the Market Advisor shall perform periodic reviews, subject to the same scope requirement.

6.9 Self-Supply

Transactions may be entered into to provide for Self-Supply of Operating Reserves. Except as noted in the next paragraph, Customers seeking to Self-Supply Operating Reserves must place the Generator(s) supplying any one of the Operating Reserves under NYISO control. The Generator(s) must meet NYISO rules for acceptability. The amount that any such Customer will be charged for Operating Reserves will be reduced by the market value of the services provided by the specified Generator(s) as determined in the NYISO Services Tariff.

~~Alternatively, Customers, including LSEs, may enter into Day-Ahead Bilateral financial Transactions, e.g., contracts-for-differences, in order to hedge against price volatility in the Operating Reserves markets.~~

6.10 Operating Reserve Charge

Each Transmission Customer engaging in an Export and each LSE pays a monthly Operating Reserves charge under the NYISO OATT equal to the sum of the hourly charges for the month. The NYISO calculates and the LSE or Transmission Customer pays the hourly charge equal to the product of:

1. Cost to the NYISO of providing all Operating Reserves less any revenues from penalties collected during each hour

2. The ratio of:

   a. The LSE's Load or the Transmission Customer's scheduled Export to
   b. The sum of all Load in the NYCA and all scheduled Exports during that hour.

~~6.2Suppliers' Responsibilities~~

~~This section describes the responsibilities of the suppliers of Operating Reserves, for 10-Minute Spinning Reserve, 10-Minute NSR, and 30-Minute reserve.~~

~~6.2.1.Responsibilities of Suppliers of 10-Minute Spinning Reserve~~

~~Class A Unit (On-Dispatch)~~

~~A generator or dispatchable load that participates in Security Constrained Dispatch (SCD).~~

~~Class B Unit (Off-Dispatch)~~

~~A generator or interruptible/dispatchable load that is not participating in SCD, but offers to provide 10-Minute Spinning Reserve to the NYISO.~~

~~Generation Resources:~~

~~All Generators selected by the NYISO as suppliers of 10-Minute Spinning Reserve must be located within the NYCA and must be under NYISO Operational Control. All Suppliers of 10-Minute Spinning Reserves selected by the NYISO must ensure that their Generators maintain and deliver the appropriate quantity of Energy when called upon by the NYISO in all hours in which they have been selected to provide 10-Minute Spinning Reserve.~~

~~Each Generator bidding to supply 10-Minute Spinning Reserve must be able to provide Energy consistent with the Reliability Rules and the NYISO Procedures when called upon by the NYISO and specifies in its Bid the amount of time for which it can supply such Energy. It must be able to provide that Energy for at least 30 minutes.~~

~~Generators also submit, as part of their basic energy bid, an emergency response rate that allows the NYISO to calculate their expected response over 10 minutes.~~

~~Demand -Side Resources:~~

~~All Demand Side Resources selected by the NYISO as Suppliers of 10-Minute Spinning Reserve must reduce consumption of the appropriate quantity of Energy when called upon by the NYISO in all hours in which they have been selected to provide 10-Minute Spinning Reserve.~~

~~Each Demand Side Resource bidding to supply 10-Minute Spinning Reserve must be able to reduce consumption of Energy consistent with the Reliability Rules and consistent with the NYISO Procedures when called upon by the NYISO and specifies in its Bid the amount of time for which it can reduce consumption of Energy. It must be able to reduce consumption for at least 30 minutes.~~ **~~Class A Unit (Status Changes) Class A Operating Reserve Status Changes~~**

~~1) If the Status of a Class A 10-Minute Spinning Reserve supplier changes from On-Dispatch to Off-Dispatch, the default presumption by the NYISO (unless otherwise notified that it will provide 10-Minute Spinning Reserve as a Class B provider) will be that this supplier is no longer providing 10-Minute Spinning Reserve.~~
~~2) If the operating capability of a Class A 10-Minute Spinning Reserve supplier drops, the default presumption by the NYISO (unless otherwise notified) will be that this supplier's Class A 10-Minute Spinning Reserve capability has dropped accordingly.~~

~~In either of the above cases, the Class A 10-Minute Spinning Reserve supplier will be charged the real-time price of operating reserve (or the day-ahead price if no real-time price exists) for the amount of the reduction for the duration of the reduction. Class B Units (Restrictions) Class B Units may not enter into alternate sales arrangements utilizing any Capacity that has been scheduled to provide Operating Reserve, in either the Day-Ahead commitment or in any subsequent commitment by the NYISO. Subject to the limitations on Installed Capacity Suppliers, if applicable, they may enter into alternate sales arrangements utilizing any Capacity that has not been scheduled to provide Operating Reserve.~~

~~6.2.2.Responsibilities of Suppliers of 10-Minute NSR & 30-Minute Reserve~~

~~Subject to the NYISO's locational requirements, suppliers of 10-Minute NSR or 30-Minute Reserve may use Generators located within the NYCA or outside the NYCA. In order for a Supplier to provide 10-Minute NSR or 30-Minute Reserve using a Generator located outside the NYCA, the operator of that Generator's Control Area must have agreed to modify the Desired Net Interchange (DNI) between the NYCA and that Control Area instantaneously upon notification by the ISO~~ NYISO ~~that the ISO NYISO is initiating a reserve pick-up for the area including that Generator. The amount of a 10-Minute NSR provided by Generators within any given external Control Area cannot exceed the maximum amount by which the operator of that Control Area will change the DNI from that Control Area into the NYCA within ten (10) minutes of the initiation of a reserve pick-up by the ISO. Likewise, the amount of 30-Minute Reserve provided by Generators within any given external control Area cannot exceed the maximum amount by which the operator of that Control Area will change the DNI from that Control Area into the NYCA within thirty (30) minutes of the initiation of a reserve pick-up by the ISO. All Generators selected by the NYISO as Suppliers of 10-Minute NSR or 30-Minute~~

~~Reserve must ensure that their Generators maintain and deliver the appropriate quantity of Energy when called upon by the NYISO in all hours in which they have been scheduled to provide 10-Minute NSR or 30-Minute Reserve.~~

~~Suppliers may not enter into alternate sales arrangements utilizing any Capacity on any Generator that has been scheduled to provide 10-Minute NSR or 30-Minute Reserve in the Day-Ahead commitment or in the Real-Time dispatch. Subject to the limitations on Installed Capacity Suppliers, if applicable, they may enter into alternate sales arrangements utilizing any Capacity that has not been scheduled to provide 10-Minute NSR or 30-Minute Reserve in either the Day-Ahead commitment or in the Real-Time dispatch. For externally supplied operating reserve that is activated, required changes in desired net interchange (DNI) need to be coordinated and verified between the NYISO and the associated control area. This will ensure reserve performance without the need for the NYISO to track the performance of an individual external supplier.~~

~~6.2.3.Responsibilities of All Suppliers~~

~~Class A Units (Restrictions)~~

~~Class A Units may not enter into alternate sales arrangements utilizing any Capacity that has been scheduled to operate or to provide Operating Reserve, in either the Day-Ahead commitment or any supplemental commitment conducted by the NYISO. They also may not increase the Energy Bids made for the portions of those Generators that have been scheduled Day-Ahead to provide 10-Minute Spinning Reserve. They may enter into alternate sales arrangements utilizing any Capacity that has not been scheduled to operate or to provide Operating Reserve.~~

~~6.3Scheduling of Service~~

~~The NYISO is responsible for scheduling the Operating Reserve service. The NYISO ensures that Operating Reserve is properly geographically located so that transmission constraints do not limit the ability to deliver Operating Reserve. The scheduling of these services involves a Day-Ahead commitment by the NYISO, a Real-Time Market evaluation, and then Real-Time Operation.~~

~~6.410-Minute Spinning Reserve Day-Ahead Market~~

~~Suppliers offering Generator or Dispatchable/Interruptible Load wishing to provide 10-Minute Spinning Reserve in the Day-Ahead commitment must submit Availability Bids for each hour of the upcoming day. The NYISO selects 10-Minute Spinning Reserve Suppliers for each hour of the upcoming day through its Day-Ahead commitment, using Bids provided by the Suppliers, including Availability Bids by both Class A and Class B Suppliers, and Energy Bids by Class A Suppliers. The NYISO notifies each Supplier of 10-Minute Spinning Reserve that has been selected in the Day-Ahead Schedule of the amount of 10-Minute Spinning Reserve it has been scheduled to provide. Suppliers of 10-Minute Spinning Reserve scheduled Day-Ahead must either provide 10-Minute Spinning Reserve or generate Energy when requested by the NYISO to do so, in all hours for which they have been selected to provide 10-Minute Spinning Reserve.~~

~~Real-Time Market:~~

~~During each Dispatch Day, Suppliers whose Generators have not been scheduled to provide~~
~~10-Minute Spinning Reserve and which still have Capacity that has not been committed for use in any other way may submit Availability Bids to provide 10-Minute Spinning Reserve to the NYISO. These Real-Time availability Bids may differ from Availability Bids that were made by those Suppliers in the Day-Ahead commitment.~~

~~If the NYISO anticipates that it will require additional 10-Minute Spinning Reserves in an hour, it selects additional Suppliers of 10-Minute Spinning Reserve from among those Suppliers that have submitted Real-Time Availability Bids to it for that hour. The NYISO makes this selection with the objective of minimizing the cost of meeting load and providing all necessary Ancillary Services in that hour. The NYISO notifies each Supplier of 10-Minute Spinning Reserve that has been selected in the Real-Time dispatch of the amount of 10-Minute Spinning Reserve it must provide.~~

~~Real-Time Operation:~~

~~The NYISO, if necessary, reduces the output on Class A Units via SCD from otherwise economic loading to provide 10-Minute Spinning Reserve capability. When reserve is activated, the NYISO measures actual performance against expected performance and charges financial penalties, as detailed in Section 6.5 of this manual, to Suppliers of 10-Minute Spinning Reserve which fail to perform in accordance with their accepted bids.~~

~~During real-time operation any unit that is On-Line and On-Dispatch and that has not been previously committed or scheduled to supply 10-Minute Spinning Reserve will be included in the calculation of total available 10-Minute Spinning Reserve. During the reserve pick-up, these units will not be subject to the performance penalties that apply to those units that have been scheduled to supply 10-Minute Spinning Reserve.~~

~~They will be moved at their normal response rates and will not be penalized for over-generating during the reserve pick-up mode.~~

~~6.3.2.10-Minute NSR & 30-Minute Reserve~~

~~Day-Ahead Market~~

~~Suppliers offering Generators or Dispatchable/Interruptible Loads wishing to provide 10-Minute NSR and/or 30-Minute Reserve in the Day-Ahead commitment must submit availability bids for each hour of the upcoming day. The NYISO selects Suppliers of 10-Minute NSR and 30-Minute Reserve for each hour of the upcoming day through the Day-Ahead commitment, using Bids and/or schedules provided by the Suppliers. The NYISO notifies each Supplier of 10-Minute NSR and/or 30-Minute Reserve that has been selected in the Day-Ahead schedule of the amount of 10-Minute NSR and/or 30-Minute Reserve it has been scheduled to provide. Suppliers of 10-Minute NSR and/or 30-Minute Reserve scheduled Day-Ahead must provide 10-Minute NSR and/or 30-Minute Reserve for all hours in which they have been scheduled to provide 10-Minute NSR and/or 30-Minute Reserve. Real-Time Market: During the day, Suppliers that have not been scheduled to provide 10-Minute NSR or 30-Minute Reserve and which still have Capacity that has not been committed for use in any other way may submit Availability Bids to provide~~

~~10-Minute NSR and/or 30-Minute Reserve to the NYISO. These Real-Time Availability Bids may differ from Availability Bids that were made by those Suppliers in the Day-Ahead commitment.~~

~~If the NYISO anticipates that additional Suppliers of 10-Minute NSR or 30-Minute Reserve are needed in an hour, it selects additional Suppliers of 10-Minute NSR or 30-Minute Reserve from among those Suppliers that have supplied Real-Time Availability Bids to it for that hour. The NYISO makes this selection with the objective of minimizing the cost of meeting Load and providing all necessary Ancillary Services in that hour.~~

~~The NYISO may perform multiple selections of Suppliers of 10-Minute NSR or 30-Minute Reserve for any given hour. Suppliers bidding to supply 10-Minute NSR or 30-Minute Reserve that have not already been scheduled to provide 10-Minute NSR or 30-Minute Reserve may change their Real-Time Bids from one hour to the next. The NYISO notifies each Supplier of 10-Minute NSR or 30-Minute Reserve that has been scheduled in the Real-Time dispatch of the amount of 10-Minute NSR or 30-Minute Reserve it must provide. Any Supplier whose bid to provide 10-Minute NSR or 30-Minute Reserve is accepted by the NYISO in the Real-Time dispatch must make its Generators or Dispatchable/Interruptible Loads available for dispatch by the NYISO.~~

~~Real-Time Operation:~~

~~Suppliers of 10-Minute NSR and 30-Minute Reserve respond to directions by the NYISO to activate these reserves. When reserve is activated, the NYISO measures actual performance against expected performance and charge financial penalties, as detailed in Section 6.5 of this manual, to Suppliers of 10-Minute NSR or 30-Minute Reserve which fail to perform in accordance with their accepted Bids.~~

~~6.6Payment and Charges for Service~~

~~This section describes the payment and charges for Operating Reserve service and covers the following:~~

~~6.7~~~~Payments to suppliers of 10-Minute Spinning ReserveSpinning Reserve~~

- ~~Payments to suppliers of 10-Minute non-synchronized reserve~~
- ~~Payments to suppliers of 30-Minute reserve~~
- ~~Operating Reserve charges~~

~~Notwithstanding anything to the contrary in this section, no payments are made to any Supplier providing Operating Reserves for reserves provided by that Supplier in excess of the amount of Operating Reserves scheduled by the NYISO either Day-Ahead, or, in any subsequent schedule. The Market-Clearing Price paid to Suppliers of any category of Operating Reserve is not determined by any Bid to supply Operating Reserve that has not been accepted by the NYISO. For more information see *NYISO Manual for Accounting & Billing*.~~

~~6.4.1.Payments to Suppliers of 10-Minute Spinning ReserveSpinning Reserve~~

~~Availability Payments~~

~~Each Supplier which the NYISO has scheduled Day-Ahead to provide 10-Minute Spinning Reserve is paid the Day-Ahead Availability price for 10-Minute Spinning Reserve in each hour, multiplied by the amount of 10-Minute Spinning Reserve that Supplier is scheduled to provide in each hour. The Day-Ahead Availability price for 10-Minute Spinning Reserve for each hour is equal to the highest Day-Ahead Availability Bid made by a Supplier that has been scheduled Day-Ahead to provide 10-Minute Spinning Reserve in that hour.~~

~~Subject to the exceptions described in Section 6.4.4 below, each Supplier whose Generator(s) provide more 10-Minute Spinning Reserve in an hour than it was scheduled Day-Ahead to provide in that hour is paid the Real-Time Availability price for 10-Minute Spinning Reserve in that hour, multiplied by the amount of 10-Minute Spinning Reserve that Supplier provided in that hour that was in excess of the amount scheduled to be provided Day-Ahead, if any. The NYISO calculates separate Real-Time Availability prices for 10-Minute Spinning Reserve for each hour. The Real-Time Availability price for 10-Minute Spinning Reserve for each hour is equal to the highest Real-Time Availability Bid made by a Supplier providing 10-Minute Spinning Reserve in that hour that is providing more 10-Minute Spinning Reserve in that hour than it had been scheduled to provide in that hour in the Day-Ahead schedule.~~

~~Acceptance of any 10-Minute Spinning Reserve Bid in the Real-Time Market does not affect the Availability price for 10-Minute Spinning Reserve that was determined Day-Ahead.~~

~~Lost Opportunity Cost Payments~~

~~Suppliers of 10-Minute Spinning Reserve whose Class A Unit output in the Real-Time dispatch has been reduced for the purpose of creating 10-Minute Spinning Reserve are paid for Lost Opportunity Costs. The Lost Opportunity Cost payment that each such Supplier receives is computed by multiplying the Marginal Lost Opportunity Cost (MLOC) in each hour by the number of MW of 10-Minute Spinning Reserve supplied by that Supplier in that hour. Attachment A of this manual presents an example that illustrates the dispatch of load and 10-Minute Spinning Reserve and the definition of MLOC payments to Class A providers.~~

~~In cases where 10-Minute Spinning Reserve is bottled (meaning that there are active transmission constraints on the locations at which 10-Minute Spinning Reserve can be supplied), MLOC will initially be calculated on a NYCA basis.~~

~~Suppliers with Class B Units scheduled for 10-Minute Spinning Reserve do not receive Lost Opportunity Cost payments.~~

~~Other Payments:~~

~~The NYISO pays the Real-Time LBMP for all Energy generated in accordance with the NYISO's instructions by Suppliers of 10-Minute Spinning Reserve. Real-Time LBMPs are computed under the assumption that all Energy generated by Class B Units supplying 10-Minute Spinning Reserve are fixed injections. Each Generator providing 10-Minute Spinning Reserves is also compensated by the NYISO if its Bid Production Cost to produce the Energy the NYISO has requested it to generate, including start-up costs, exceeds the revenues it receives from the sale of Energy at LBMP prices.~~

~~6.7.1Payments to Suppliers of 10-Minute Non-Synchronized Reserve~~

~~*Availability Payments*~~

~~Each Supplier which the NYISO has scheduled Day-Ahead to provide 10-Minute NSR is paid the Day-Ahead Availability price for 10-Minute NSR in each hour multiplied by the amount of 10-Minute NSR that Generator is scheduled to provide in each hour. The Day-Ahead Availability price for 10-Minute NSR for each hour is equal to the highest Day-Ahead Availability Bid made by a Supplier that has been scheduled Day-Ahead to provide 10-Minute NSR in that hour.~~

~~Subject to the exceptions described in Section 6.4.4 below, each Supplier which provides more 10-Minute NSR than it was scheduled Day-Ahead to provide in that hour is paid the Real-Time Availability price for 10-Minute NSR, multiplied by the amount of 10-Minute NSR that Generator provided in that hour that was in excess of the amount scheduled to be provided Day-Ahead, if any. The NYISO calculates separate Real-Time Availability prices for 10-Minute NSR for each hour. The Real-Time Availability price for 10-Minute NSR for each hour is equal to the highest Real-Time Availability Bid made by a Supplier providing 10-Minute NSR in that hour that is providing more 10-Minute NSR in that hour than it had been scheduled to provide in that hour in the Day-Ahead schedule.~~

~~Acceptance of any Supplier's Bid to supply 10-Minute NSR in the Real-Time Market does not affect the Availability price for 10-Minute NSR that was determined Day-Ahead.~~

~~*Other Payments*~~

~~The NYISO pays the Real-Time LBMP for all Energy generated in accordance with the NYISO's instructions by Suppliers of 10-Minute NSR. Each 10-Minute NSR Supplier is also compensated by the NYISO if its Bid Production Cost to produce the Energy the NYISO has requested it to generate, including start-up costs, exceeds the revenues it receives from the sale of Energy at LBMP prices.~~

~~6.7.3Payments to Suppliers of 30-Minute Reserve~~

~~*Availability Payments*~~

~~Each Supplier scheduled Day-Ahead to provide 30-Minute Reserve is paid the Day-Ahead Availability price for 30-Minute Reserve in each hour, multiplied by the amount of 30-Minute Reserve that the Supplier is scheduled to provide in each hour. The Day-Ahead Availability price for 30-Minute Reserve for each hour is equal to the highest Day-Ahead Availability Bid made by a Supplier that has been scheduled Day-Ahead to provide 30-Minute Reserve in that hour.~~

~~Subject to the exceptions described in Section 6.4.4 below, each Supplier which provides more 30-Minute Reserve than it was scheduled Day-Ahead to provide in each hour is paid the Real-Time Availability price for 30-Minute Reserve, multiplied by the amount of 30-Minute Reserve that the Supplier provided in that hour that was in excess of the amount scheduled to be provided Day-Ahead, if any. The NYISO calculates separate Real-Time Availability prices for 30-Minute Reserve for each hour. The Real-Time Availability price for 30-Minute Reserve for each hour is equal to the highest Real-Time Availability Bid made by a Supplier providing 30-Minute Reserve in that hour that is~~

~~providing more 30-Minute Reserve in that hour than it had been scheduled to provide in that hour in the Day-Ahead schedule. Acceptance of any Bid to supply 30-Minute Reserve in the Real-Time Market does not affect the Availability price for 30-Minute Reserve that was determined Day-Ahead.~~

~~Other Payments~~

~~The NYISO pays the Real-Time LBMP for all Energy generated in accordance with the NYISO's instructions by Suppliers of 30-Minute Reserve. Each Supplier providing 30-Minute Reserve is also compensated by the NYISO if its Bid Production Cost to produce the Energy the NYISO has requested it to generate, including start-up costs, exceeds the revenues it receives from the sale of Energy at LBMP prices.~~

~~6.7.5Operating Reserve Charge~~

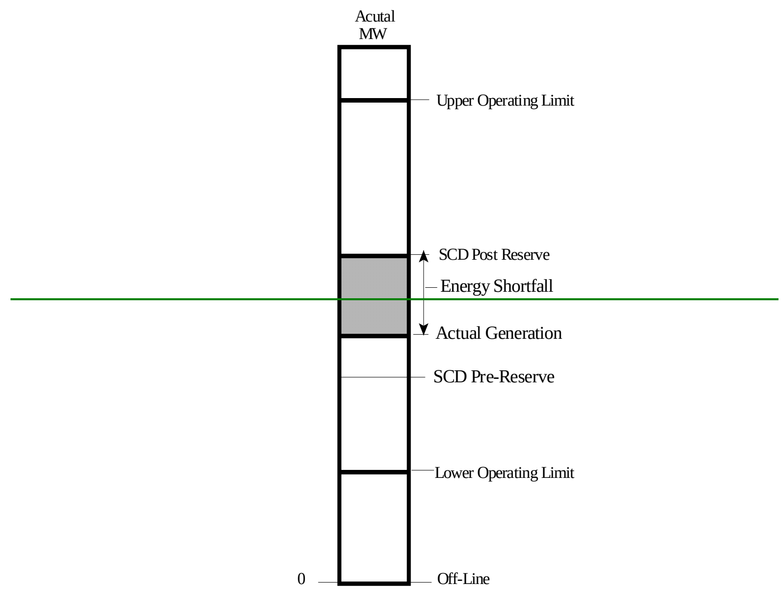
~~Each Transmission Customer engaging in an Export and each LSE pays a monthly Operating Reserves charge under the ISO NYISO OATT equal to the sum of the hourly charges for the month. The NYISO calculates and the LSE or Transmission Customer pays the hourly charge equal to the product of (A) cost to the NYISO of providing all Operating Reserves less any revenues from penalties collected during each hour and (B) the ratio of (i) the LSE's Load or the Transmission Customer's scheduled Export to (ii) the sum of all Load in the NYCA and all scheduled Exports during that hour.~~

6.11 Failure to Provide Operating Reserve

There is no penalty for failing to perform under RTS, other than incurring an ~~regulation~~under-generation penalty. If the unit does not perform, the following will occur:

- RTD converted the reserve schedule to energy (i.e., the reserve schedule went to zero) and the unit would buy out of its day-ahead commitment.
- The unit would not receive any payment for energy produced.
- For more information, see ***NYISO Manual for Accounting & Billing***.

~~Providers in the Day-Ahead market are obligated to provide reserve when called upon by the NYISO. Performance measures for each category of Operating Reserve are monitored.~~
~~Figure 6.5 shows the financial penalties that can be assessed to units that are providing reserve in the Reserve Pickup mode.~~
~~For more information see *NYISO Manual for Accounting & Billing*.~~



~~Figure 6.5: Reserve Pickup Penalty~~

~~If a Supplier scheduled Day-Ahead to provide Operating Reserve trips off-line and consequently is unable to provide 10-Minute Spinning Reserve, it is charged the Real-Time Availability price in each hour applied to the amount of 10-Minute Spinning Reserve it was scheduled Day-Ahead to provide.~~

~~If the NYISO calls for a Supplier of any category of Operating Reserves (other than a Supplier that has previously tripped off-line and notified the ISO that it has tripped) to generate Energy with part or all of the Capacity that the NYISO has scheduled to provide any category of Operating Reserves, and that Supplier fails to provide the amount of Energy requested by the NYISO within the time applicable for the scheduled Operating Reserves (10 or 30 minutes), the NYISO takes the following actions:~~

- ~~does not pay the non-performing Supplier for any shortfall in the amount of Energy provided~~
- ~~charges the Supplier for any shortfall in the amount of Energy provided, at the Real-Time LBMP for Energy at that Supplier's location~~
- ~~charges the Supplier a regulation penalty~~
- ~~reduces any Availability payments for the scheduled Operating Reserve, and any Lost Opportunity Cost payments, if applicable, that the Supplier would otherwise have received for the 24-hour billing period in which that Supplier failed to perform as scheduled. The Availability payments and the Lost Opportunity Cost payments, if applicable, that the Supplier would have received are calculated by multiplying the lowest ratio of the amount of Energy supplied to the amount of Energy scheduled, during any activation of that Supplier during that 24-hour billing period by the applicable Availability payments and Lost Opportunity Cost payments, if applicable, that the Supplier would otherwise have received.~~

~~If a supplier that has been selected to provide reserve availability does not comply fully with an ISO reserve pick-up request, then the payments for reserve availability shall be multiplied by the Daily Average Pick-Up Ratio, applied to each hour in that day, except for hours in which the unit tripped off-line and notified the ISO that it had tripped.~~

~~The Daily Average Pick-Up Ratio, for each day, is defined as:~~

~~Total Actual MW Picked-Up for ISO~~

~~Daily Average Pick-Up Ratio = --~~

~~Total MW Pick-Up Requested by ISO~~

~~For Example, assume a supplier is requested to provide 10 MW reserve pickup in hours 2, 4, 6, 8 14 and 16. It actually provides reserve pick-ups of 8 MW, 6 MW, 4 MW, trips off-line, 0 MW, and 8 MW for those respective hours. In this case, its Daily Average Supply Ratio would be:~~

~~8+6+4+0+8~~

~~Daily Average Pick-Up Ratio = --------------------------- = 0.52~~

~~10+10+10+10+10~~

~~Note that those hours during which a unit tripped off-line, while responding to the ISO reserve pick-up request, are not counted.~~

~~The operating reserve availability payment, for each hour in that day, will be multiplied by this Daily Average Pick-up Ratio (i.e., 0.52 in this example). Thus, if the reserve availability payments, for the 10 MW, were $100 + $100 + $100 + $200 + $400 + $600 for the six requested hours, then the payments would be $52 + $52 +$52 + + $0 + ($600)(.52) = $468 for the Hours 2, 4, 6, 8, 14, and 16. The unit would also be paid for energy produced at LBMP.~~

~~If a Generator providing Operating Reserve has repeatedly failed to provide Energy when called upon by the NYISO, the NYISO may preclude that Generator from providing Operating Reserve in the future. If a specific Generator has been precluded from supplying Operating Reserve, the NYISO will require that Generator to pass a re-qualification test before accepting any additional Bids to supply Operating Reserves from that Generator.~~

6.12 Procedures for Notification of Poor Performers

The following procedures are for notifying suppliers in the event that they exhibit poor Operating Reserve performance.

In the initial LBMP implementation, these procedures will be performed at the end of each billing cycle.

NYISO Actions

The NYISO shall perform the following:

1~~)~~) Notify the poor performing supplier via telephone or E-mail, upon determination by the NYISO that the supplier is exhibiting poor performance.

2~~)~~) Notify the poor performing supplier that they are currently being penalized as described in the ***NYISO Manual for Accounting & Billing*** and that persistent non-compliance in accordance with this procedure will result in additional penalties, and that consistent or continued poor performance will result in the provider being removed from the bidders list.

Reserve Provider Actions

The poor performer shall acknowledge the NYISO notification and report their expectation of the time they will be able to return to normal performance. The provider shall also describe the cause of their poor performance.

7. BLACK START CAPABILITY SERVICE

This section describes the black start capability service.

7.1 Description

Black start capability represents the key Generators that, following a system-wide blackout, can start without the availability of an outside electric supply and are available to participate in system restoration activities that are under the control of the NYISO or, in some cases, under local Transmission Owner Control. If a partial or system-wide blackout occurs, these units assist in the restoration of the New York Control Area (NYCA). Specific generating units, identified in the NYISO Restoration Plan or, in specific Transmission Owners' local restoration plan(s), have the capability and training required to start up without the presence of a synchronized grid to provide the necessary auxiliary station power.

The NYISO Restoration Plan and/or Transmission Owner restoration plan(s) are implemented if a partial or complete system blackout occurs. The NYISO selects the generating resources with black start capability by considering the following operating characteristics:

- electrical location in the NYCA
- startup time: from NYISO order to start to minimum output
- maximum response rate (MW/minute) above minimum output
- maximum power output

7.2 Source & Scheduling of Service

LSEs must purchase black start capability service from the NYISO. Generation Resources providing this service must successfully pass the test for black start capability.

The NYISO identifies the generating units that are in critical areas for NYS Power System restoration. During system restoration activities, the NYISO manages and deploys the black start capability, as needed, depending on the specific situation.

The NYISO develops and periodically reviews the Black Start Restoration Plan for the NYS Power System. The NYISO may amend this restoration plan and determine Black Start requirements to account for changes in system configuration if the NYISO determines that additional Black Start resources are needed. The NYISO has the flexibility to seek bids for new resources whenever it amends the current plan.

Although the ~~ISO~~NYISO plan will restore a major portion of the state electric system, portions of the local Transmission Owner restoration plans may require some additional Black Start Generators, which are located in local Transmission Owner areas and which are not presently listed in the ~~ISO~~NYISO restoration plan. The ~~ISO~~NYISO will make payments for local area Black Start Capability directly to the generating facilities that provide that service. Those payments will be determined under the terms of this Rate Schedule. The LSEs in those local Transmission Owner areas will be additionally charged for that Black Start

Capability Service by the ~~ISO~~NYISO. Generating facilities, which are obligated to provide Black Start Service as a result of divestiture contract agreements, will not receive ~~ISO~~NYISO payments for that service if they are already compensated for such service as part of those divestiture contracts.

7.3 Payment or Service

Initially, the embedded costs and O & M expenses of the equipment required to provide black start capability service are recovered by the suppliers in return for making equipment available to provide Black Start capability service, to the NYISO. For more information, see the *NYISO Manual for Accounting & Billing*.

Payments are made to Generators that are included in the NYISO's Black Start Restoration Plan as well as to Generators included in any Transmission Owner's local restoration plan. The Generators that are designated in these plans are paid at a rate, which is approved by FERC.

By May 1st of each year, the following embedded cost information for Black Start equipment located at one of these Generators is provided to the NYISO based upon FERC Form No. 1 or equivalent data:

1. Capital and fixed operation and maintenance costs associated with only those facilities within Generators that provide Black Start Capability
2. Annual costs associated with training the Generator operators in system restoration.

LSEs taking service under the OATT pay a monthly Black Start Capability Charge on all Transactions to supply Load in the NYCA (including in-state Bilateral Transactions, purchases of Energy from the LBMP Market, and Import transactions) as follows:

$$BSC_{s,t} = ISOBSC_t \frac{L_{x,t}}{\sum\limits_{x \varepsilon N} L_{x,t}} + TOBSC_t \frac{L_{x,t}}{\sum\limits_{x \varepsilon T_x} L_{x,t}}$$

Where:

$BSC_{x,t}$	=	black start charge for LSE x during month t~~;~~
$ISOBSC_t$	=	NYISO black start costs for month t~~;~~
$L_{x,t}$	=	LSE x's load during month t~~;~~
N	=	set of LSEs in the NYCA~~;~~
$TOBSC_t$	=	Transmission Owner black start costs for month t~~; and~~
T_x	=	set of LSEs in LSE x's Transmission District

The ~~ISO~~NYISO (and Transmission Owner, when applicable) shall conduct Black Start Capability tests for providers of Black Start Capability. Any Generator, which ~~that~~ is awarded Black Start Capability payments and fails a Black Start capability test, shall forfeit all Black Start capability payments made to that Generator since its last successful test. Payments to that Generator shall not resume until it successfully passes the Black Start Capability test.

7.4 Black Start Service Procedures

The following procedures apply to black start capability service:

NYISO Actions

The NYISO Staff shall perform the following:

1. On a periodic basis, determine the amount and location for black start capability generation.
2. Select the Generators for black start capability based on location, price, and quality of supply.
3. Notify the selected generators for black start testing.

Black Start Generator Actions

The Black Start suppliers shall perform the following:

1. On an annual basis, provide the NYISO with embedded cost information.
2. Submit to performance testing when requested by the NYISO.

Attachment A –
Dispatch Load & Spinning Reserve

This attachment illustrates the dispatch of load and spinning reserve and the definition of LOC payments to Class A providersFlexible Units. This example is based on the following assumptions for a given operating hour:

- generators are ordered to run according to the sequence that was established by unit commitment
- all spinning reserves are available within 10 minutes and all non-synchronized reserves are available within 30 minutes
- generator capacity, minimum load, minimum load cost, and running cost bid are given as shown in Table A.1.
- total load demand for the hour is 800 MW
- operating reserve requirement for the hour is 300 MW of which 150 MW must be spinning and available within 10 minutes
- the affects of transmission losses and congestion are not considered in this example

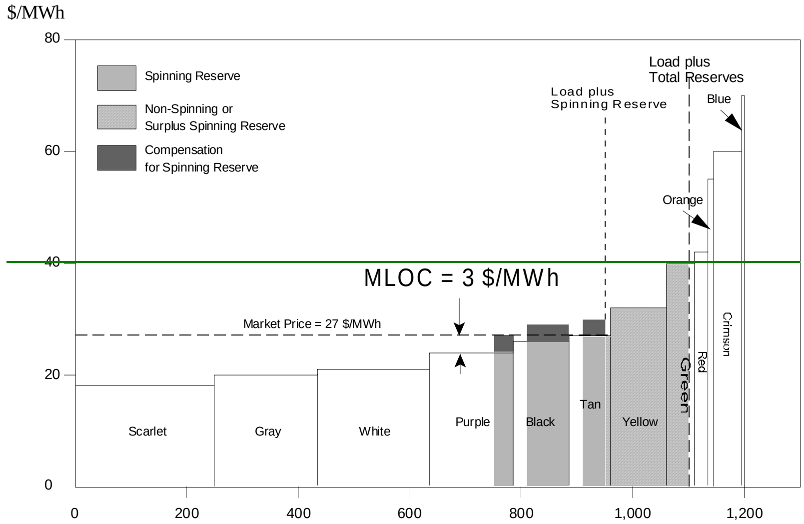
Table A.1: Load & Spinning Reserve Dispatch

Generator Name	Capacity (MW)	Minimum (MW)	Min Load Payment ($/Hr)	Run Cost Bid ($/MWh)	Dispatch Generation (MW)	Dispatch Spin Res (MW)	Spin Res Payment ($/Hr)	Surplus Spin Res (MW)	Non-Spin Res (MW)
Blue	5	2	150	70	0	0	0	0	0
Crimson	50	10	650	60	0	0	0	0	0
Orange	10	5	300	55	0	0	0	0	0
Red	25	0	0	42	0	0	0	0	0
Green	50	10	450	40	0	0	0	0	40
Yellow	100	10	350	32	0	0	0	0	100
Tan	75	25	750	27	25	40	120	10	0
Black	100	25	700	26	25	75	225	0	0
Purple	150	25	650	24	115	35	105	0	0
White	200	50	1100	21	200	0	0	0	0
Gray	185	50	1050	20	185	0	0	0	0
Scarlet	250	100	2000	18	250	0	0	0	0
TOTAL	1200	312			800	150		10	140

Total Load = 800 MW

Spinning Reserve Requirement = 150 MW

Operating Reserve Requirement = 300 MW



~~**Figure A-1: Load & Spinning Reserve Dispatch**~~

~~Table A.1 and Figure A.1 show the results of the dispatch. The results are summarized as follows:~~

- ~~Generators are loaded in "merit-order" according to their running cost bids.~~
- ~~Minimum load costs are paid, but do not affect the dispatch.~~
- ~~The required on-line capacity is 950 MW (800 + 150 = 950 MW) and is obtained by running units Scarlet through Tan.~~
- ~~The market price of $27 MWh is equal to the running cost bid of the Tan unit, i.e., the last unit to be "turned on.".~~
- ~~The LOC of $3 MWh is established as the difference between the market price and lowest running cost bid of a unit that is carrying spinning reserve (i.e., the Purple unit).~~
- ~~The LOC payment is shown in Table A.1 and is calculated as the product of LOC (in $/MWh) and the dispatched spinning reserve. Surplus spinning reserve receives no LOC payment.~~
- ~~A spinning reserve surplus of 10 MW is available from the Tan unit and can contribute towards the Operating Reserve.~~
- ~~The non-synchronized reserve is obtained from the Yellow and Green units.~~

Attachment ~~B~~ A –
Generator MVAR Capability Test

NYISO Voltage Support Ancillary Service Annual Reactive Capability Test Repo

Generator Owner	*(enter owner name)*
Unit Name	*(enter generator name)*
Unit Number	*(enter unit number)*
NYISO MIS PTID	*(enter ID number)*
Generator ICAP/DMNC Rating	*(enter DMNC MW-rating)*

NOTE: Reporting entity should complete all fields highlighted in yellow on this sheet, and all appropriate fields on the lag and lead test data sheets. Data recorded on the test data sheets will automatically populate into this summary sheet. (Rev. 8/3/2004)

LAGGING MVAR MAXIMUM CAPABILITY TEST

Test Date:	***(enter mm/dd/yyyy)***
Start Time	***(enter hh.mm)***
End Time	***(enter hh.mm)***

NOTE: Cells shaded light green are automatically populated from the test data sheets.

	Gross Generator Output		Net Output to system			Gen. Terminal Voltage		Tap Positions		In-plant Auxiliary Station Service Load	
	Gross Real Power MW	Gross Reacitve Power MVAr	Net Real Power MW	Net Reactive Power MVAr	Hydrogen Pressure (PSIA)	Gen Terminal	Auxiliary Bus	GSU	Auxiliary Bus	MW	MVAR
HP or CT (Unit/Part 1)						0.0	0.0	0.0	0.0	0.0	0.0
LP or ST (Unit/Part 2)						0.0	0.0	0.0	0.0	0.0	0.0

LEADING MVAR MAXIMUM CAPABILITY TEST

Test Date:	***(enter mm/dd/yyyy)***
Start Time	***(enter hh.mm)***
End Time	***(enter hh.mm)***

NOTE: Cells shaded light green are automatically populated from the test data sheets.

	Gross Generator Output		Net Output to system			Gen. Terminal Voltage		Tap Positions		In-plant Auxiliary Station Service Load	
	Gross Real Power MW	Gross Reacitve Power MVAr	Net Real Power MW	Net Reactive Power MVAr	Hydrogen Pressure (PSIA)	Gen Terminal	Auxiliary Bus	GSU	Auxiliary Bus	MW	MVAR
HP or CT (Unit/Part 1)						0.0	0.0	0.0	0.0	0.0	0.0
LP or ST (Unit/Part 2)						0.0	0.0	0.0	0.0	0.0	0.0

Note: Annual test requirement is LAGGING test at (at least) 90% Rated DMNC and LEADING test at normal low limit.

COMMENTS: ______________________

NYISO SHIFT SUPERVISOR: ______________________

TRANSMISSION PROVIDER DISPATCHER: ______________________

REACTIVE SUPPLIER: ______________________

NYISO Voltage Support Ancillary Service Annual Reactive Capability Test Report

Generator Owner	*(enter owner name)*
Unit Name	*(enter generator name)*
Unit Number	*(enter unit number)*
NYISO MIS PTID	*(enter ID number)*
Generator ICAP/DMNC Rating	*(enter DMNC MW-rating)*

NOTE: Reporting entity should complete all fields highlighted in yellow on this sheet, and all appropriate fields on the lag and lead test data sheets. Data recorded on the test data sheets will automatically populate into this summary sheet. (Rev. 8/3/2004)

LAGGING MVAR MAXIMUM CAPABILITY TEST

Test Date:	*(enter mm/dd/yyyy)*
Start Time	*(enter hh.mm)*
End Time	*(enter hh.mm)*

NOTE: Cells shaded light green are automatically populated from the test data sheets.

	Gross Generator Output		Net Output to system			Gen. Terminal Voltage		Tap Positions		In-plant Auxiliary Station Service Load		Reason For Limit
	Gross Real Power MW	Gross Reacitve Power MVAr	Net Real Power MW	Net Reactive Power MVAr	Hydrogen Pressure (PSIA)	Gen Terminal	Auxiliary Bus	GSU	Auxiliary Bus	MW	MVAR	
HP or CT (Unit/Part 1)						0.0	0.0	0.0	0.0	0.0	0.0	
LP or ST (Unit/Part 2)						0.0	0.0	0.0	0.0	0.0	0.0	

LEADING MVAR MAXIMUM CAPABILITY TEST

Test Date:	*(enter mm/dd/yyyy)*
Start Time	*(enter hh.mm)*
End Time	*(enter hh.mm)*

NOTE: Cells shaded light green are automatically populated from the test data sheets.

	Gross Generator Output		Net Output to system			Gen. Terminal Voltage		Tap Positions		In-plant Auxiliary Station Service Load		Reason For Limit
	Gross Real Power MW	Gross Reacitve Power MVAr	Net Real Power MW	Net Reactive Power MVAr	Hydrogen Pressure (PSIA)	Gen Terminal	Auxiliary Bus	GSU	Auxiliary Bus	MW	MVAR	
HP or CT (Unit/Part 1)						0.0	0.0	0.0	0.0	0.0	0.0	
LP or ST (Unit/Part 2)						0.0	0.0	0.0	0.0	0.0	0.0	

Note: Annual test requirement is LAGGING test at (at least) 90% Rated DMNC and LEADING test at normal low limit.

COMMENTS: ______________________

NYISO SHIFT SUPERVISOR: ______________________ TRANSMISSION PROVIDER DISPATCHER: ______________________

REACTIVE SUPPLIER: ______________________

Figure ~~B~~A-1: NYISO Voltage Support Ancillary Service Annual Reactive Capability Test Report

Lagging Test Data Recording Form - Part 1

Reading	*for the high pressure turbine-generator set of a cross-compound unit, or the combustion turbine-generator set of a combined-cycle unit.* Time	Gross Generator Output: Gross Real Power MW	Gross Generator Output: Gross Reacitve Power MVAr	Net Output to system: Net Real Power MW	Net Output to system: Net Reactive Power MVAr	Hydrogen Pressure (PSIA)	Gen. Terminal Voltage: Gen Terminal	Gen. Terminal Voltage: Auxiliary Bus	Tap Positions: GSU	Tap Positions: Auxiliary Bus	In-plant A Station Ser MW
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13											

Calculated Average value for hour

These cells are automatically calculated and result populated in the test report sheet.
Data to be supplied at 5-minute intervals for duration of test hour.
Values need only be supplied at beginning and end of test hour.

Use Part 2 only for LP-shaft of cross-compound or steam turbine portion of combined-cycle unit when tested at the same time as generator in P

Lagging Test Data Recording Form - Part 2

Reading	*for the low pressure turbine-generator set of a cross-compound unit, or the HRSG steam turbine-generator set of a combined-cycle unit.* Time	Gross Generator Output: Gross Real Power MW	Gross Generator Output: Gross Reacitve Power MVAr	Net Output to system: Net Real Power MW	Net Output to system: Net Reactive Power MVAr	Hydrogen Pressure (PSIA)	Gen. Terminal Voltage: Gen Terminal	Gen. Terminal Voltage: Auxiliary Bus	Tap Positions: GSU	Tap Positions: Auxiliary Bus	In-plant A Station Ser MW
1											
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Calculated Average value for hour

Lagging Test Data Recording Form - Part 1

Reading	*for the high pressure turbine-generator set of a cross-compound unit, or the combustion turbine-generator set of a combined-cycle unit.*	Gross Generator Output		Net Output to system			Gen. Terminal Voltage		Tap Positions		In-plant Auxiliary Station Service Load	
Reading	Time	Gross Real Power MW	Gross Reacitve Power MVAr	Net Real Power MW	Net Reactive Power MVAr	Hydrogen Pressure (PSIA)	Gen Terminal	Auxiliary Bus	GSU	Auxiliary Bus	MW	MVAR
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13												

Calculated Average value for hour

These cells are automatically calculated and result populated in the test report sheet.
Data to be supplied at 5-minute intervals for duration of test hour.
~~*Values need only be supplied at beginning and end of test hour.*~~

Use Part 2 only for LP-shaft of cross-compound or steam turbine portion of combined-cycle unit when tested at the same time as generator in Part 1.

Lagging Test Data Recording Form - Part 2

Reading	*for the low pressure turbine-generator set of a cross-compound unit, or the HRSG steam turbine-generator set of a combined-cycle unit.*	Gross Generator Output		Net Output to system			Gen. Terminal Voltage		Tap Positions		In-plant Auxiliary Station Service Load	
Reading	Time	Gross Real Power MW	Gross Reacitve Power MVAr	Net Real Power MW	Net Reactive Power MVAr	Hydrogen Pressure (PSIA)	Gen Terminal	Auxiliary Bus	GSU	Auxiliary Bus	MW	MVAR
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13												

Calculated Average value for hour

Figure ~~B~~A-2: Lagging Test Data Recording Form - Part 1

Leading Test Data Recording Form - Part 1

Reading	*for the high pressure turbine-generator set of a cross-compound unit, or the combustion turbine-generator set of a combined-cycle unit.* Time	Gross Generator Output: Gross Real Power MW	Gross Generator Output: Gross Reacitve Power MVAr	Net Output to system: Net Real Power MW	Net Output to system: Net Reactive Power MVAr	Hydrogen Pressure (PSIA)	Gen. Terminal Voltage: Gen Terminal	Gen. Terminal Voltage: Auxiliary Bus	Tap Positions: GSU	Tap Positions: Auxiliary Bus	In-plant / Station Ser: MW
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2											
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12											
13											
Calculated Average value for hour											

These cells are automatically calculated and result populated in the test report sheet.
Data to be supplied at 5-minute intervals for duration of test hour.
Values need only be supplied at beginning and end of test hour.

Use Part 2 only for LP-shaft of cross-compound or steam turbine portion of combined-cycle unit when tested at the same time as generator in l

Leading Test Data Recording Form - Part 2

Reading	*for the low pressure turbine-generator set of a cross-compound unit, or the HRSG steam turbine-generator set of a combined-cycle unit.* Time	Gross Generator Output: Gross Real Power MW	Gross Generator Output: Gross Reacitve Power MVAr	Net Output to system: Net Real Power MW	Net Output to system: Net Reactive Power MVAr	Hydrogen Pressure (PSIA)	Gen. Terminal Voltage: Gen Terminal	Gen. Terminal Voltage: Auxiliary Bus	Tap Positions: GSU	Tap Positions: Auxiliary Bus	In-plant / Station Ser: MW
1											
2											
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Calculated Average value for hour											

Leading Test Data Recording Form - Part 1

	for the high pressure turbine-generator set of a cross-compound unit, or the combustion turbine-generator set of a combined-cycle unit.	Gross Generator Output		Net Output to system			Gen. Terminal Voltage		Tap Positions		In-plant Auxiliary Station Service Load	
Reading	**Time**	**Gross** Real Power MW	**Gross** Reacitve **Power MVAr**	**Net Real Power MW**	**Net Reactive Power MVAr**	**Hydrogen Pressure (PSIA)**	**Gen Terminal**	**Auxiliary Bus**	**GSU**	**Auxiliary Bus**	**MW**	**MVAR**
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Calculated Average value for hour												

These cells are automatically calculated and result populated in the test report sheet.
Data to be supplied at 5-minute intervals for duration of test hour.
~~***Values need only be supplied at beginning and end of test hour.***~~

Use Part 2 only for LP-shaft of cross-compound or steam turbine portion of combined-cycle unit when tested at the same time as generator in Part 1.

Leading Test Data Recording Form - Part 2

	for the low pressure turbine-generator set of a cross-compound unit, or the HRSG steam turbine-generator set of a combined-cycle unit.	Gross Generator Output		Net Output to system			Gen. Terminal Voltage		Tap Positions		In-plant Auxiliary Station Service Load	
Reading	**Time**	**Gross** Real Power MW	**Gross** Reacitve **Power MVAr**	**Net Real Power MW**	**Net Reactive Power MVAr**	**Hydrogen Pressure (PSIA)**	**Gen Terminal**	**Auxiliary Bus**	**GSU**	**Auxiliary Bus**	**MW**	**MVAR**
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11												
12												
13												
Calculated Average value for hour												

Figure ~~B~~A-3: Leading Test Data Recording Form - Part 1

Attachment ~~C~~ B –
AGC Functional Requirements

This attachment is used to describe the functional requirements for interim and final AGC.

AGC FUNCTIONAL REQUIREMENTS

~~OVERVIEW OF PHASED AGC IMPLEMENTATION~~

~~Automatic Generation Control (AGC) will be implemented in three phases – Interim, Transition, and End-State.~~

~~Interim AGC:~~

~~During Interim AGC operation, Transmission Providers (TPs) will continue to operate as Satellites within the New York Control Area (NYCA). The Interim AGC function, in a manner similar to the existing AGC at the NYISO, will allocate the calculated Pool Control Error for the NYCA to each TP (Satellite) by means of Area Participation Factors (APFs) based on the contracted regulation response rate bids from the generating units located in each TP's area. If a TP's area has no regulating units under contract, its APF will be set to zero. The control error allocated to each TP (Satellite Control Error or SCE) will be determined by multiplying the NYCA Pool Control Error by its APF. The NYISO will send an updated SCE value to each TP every six seconds.~~

~~The Security Constrained Dispatch (SCD) function at the NYISO, in a manner similar to the existing SCD, will determine unit basepoints for both regulating and non-regulating units each time it executes. SCD nominally executes every 5 minutes and may execute as often as every 2.5 minutes if conditions warrant. SCD doesn't execute just prior to the start of the hour but runs 30 seconds after the start of each hour to set the basepoints for units that are scheduled hourly. SCD Basepoints represent the desired generation five minutes in the future. The NYISO will send these 5-minute SCD basepoints for all units in a TP's area to each TP whenever SCD executes.~~

~~Based on the 5-minute SCD basepoints, Interim AGC will calculate a Ramped SCD Basepoint for each unit every six seconds. The Ramped SCD Basepoint will change linearly from either the previous 5-minute basepoint or the actual generation at the last run of SCD to the new 5-minute basepoint value.~~

~~Once every six seconds, Interim AGC will calculate a Unit Desired Generation (UDG) value for each unit in the NYCA. For a non-regulating unit, UDG will equal its Ramped SCD Basepoint. For a regulating unit, a regulating term will be added to its ramped SCD basepoint determined as described below.~~

~~Once an hour, the Interim AGC will calculate a Unit Participation Factor (UPF) for each regulating unit. The UPF will equal the ratio of the contracted regulation response rate for that unit to the total contracted regulation response rate for all regulating units in the same TP area. Based upon this UPF, Interim AGC will calculate every six seconds a UDG equal to [Ramped SCD Basepoint + UPF*SCE] for each regulating unit.~~

~~Once every six seconds, the NYISO will send to each TP the UDGs and UPFs for all units in that TP's area (with UPFs for non-regulating units set to zero).~~

~~Ideally, each TP should control all of its units using the UDG values. Under Interim AGC, however, a TP may elect to ignore these values and simply control non-regulating units to their new basepoints and allocate the SCE value to generating units that have been committed by the ISO for regulation in its area in whatever manner it chooses. Since the NYISO will not be able to verify the specific control values being sent to individual units under Interim AGC, the NYISO will judge the regulation performance of the Satellite as a whole. Regulation penalties for slow~~

~~response to SCE, if any, would be based upon the performance of the entire TP (Satellite) without regard to the performance of specific individual units.~~

~~Transition AGC:~~

~~In parallel with the implementation and testing of the new NYISO End-state AGC function, each TP will convert its local AGC subsystem to simply retransmit Unit Desired Generation (UDG) values calculated at the NYISO to all the regulating and non-regulating generating units in its control area. During testing, all TPs as a group will be requested to switch back and forth between this new mode of AGC operation and the Interim AGC operation until all operational problems have been resolved at each TP and at the NYISO.~~

~~End-State AGC:~~

In the ~~End-State~~ AGC implementation~~phase~~, ~~TP~~TOs will ~~discontinue Satellite AGC operation and simply~~ retransmit UDGs from the NYISO to individual generating units. The ~~End-state~~ AGC function will calculate area control error and allocate this error to selected regulating units. ~~End-state~~ AGC will determine the UDG for each unit by combining the unit's regulation requirement (if any) with its ramped basepoint derived from its ~~SCD~~RTD 5-minute basepoint. The NYISO computer system will send UDGs to ~~TP~~TOs that will in turn retransmit the UDGs to generating units in their control area. Regulation penalties for all NYCA units will be assigned by the NYISO directly to individual generating units based on their monitored performance.

~~Schedule:~~

~~Interim AGC based upon Market bids will be in operation on the first day of NYISO operations under the Market-based Tariff. Individual UDGs for regulating units will be implemented prior to this date but the schedule for this has not yet been established. The proposed schedule for End-state AGC will be determined jointly between the Vendor and the NYISO.~~

AGC GENERAL

Automatic Generation Control (AGC) shall provide supplementary control to automatically adjust the power outputs of generating units in the NYCA in response to changes in system net interchange and system frequency and that implements the unit basepoints calculated by NYISO's ~~SCD~~RTD function.

The AGC function shall execute periodically, with a user adjustable period initially set to six seconds.

~~This functional description of AGC is organized in the following six major areas:~~

- AGC Preprocessing (Section 6.3)
- Determination of AGC Control State, Area Control Error and Area Requirement (Section 6.4)
- Select Specific Generating Units for Regulation (Section 6.5)
- Unit Desired Generation (Section 6.6)
- Monitor Conditions to Request Immediate SCD Execution (Section 6.7)
- Unit Response Testing (Section 6.8).

AGC PROCESSING

The AGC function shall begin by preprocessing ~~real-time~~Real-Time inputs from the NYCA, including unit actual generation MW values, tie-line MW values, and system frequency. AGC shall also calculate the total Actual Net Interchange and Ramped Desired Net Interchange, and determine the ramped values of new unit basepoints calculated by ~~Security Constrained Dispatch~~Real-Time Dispatch (~~SCD~~RTD).

AGC Real-Time Measurements, System Data, and Unit Data:

Real-time data will be scanned by the NYISO EMS computer system every six seconds and will be available in the NYISO mainframe database denoted as the In-Core Data Area (ICDA). The following ~~real-time~~Real-Time values will be provided to AGC in the ICDA:

- Tie-line Values (MW)
- Net Unit Actual Generation Values (MW)
- Actual Frequency (Hz) (multiple values with one selected by the dispatcher)
- Upper and Lower Operating Limits for each unit (MW)
- Unit Operating Status Flags (On-Line, On-Dispatch, On-Control).

A telemetry status byte accompanying each data value will indicate whether or not the telemetered value is currently being updated by its source and whether or not it is considered to be valid. Automatic Generation Control shall use this status, along with a comparison of the value with individually user adjustable high and low reasonability limits, to create a data quality code for each value.

Confirmed invalid data shall generate an alarm message to the dispatcher and shall help determine whether or not AGC is suspended or tripped (see Section 6.4.1, AGC Control States).

The following system data will be provided to AGC in the ICDA by other NYISO functions:

- Desired Net Interchange, Start Time, and Ramp Interval
- Inadvertent Payback Setter
- Array of [(Tie Line MWh) –(Integral of Tie Line MW)] Values
- Scheduled Frequency
- Net Interchange Offset
- Active Security Constraints.

The following unit data will be provided to AGC via the ICDA:

- Normal Response Rates
- Regulation Response Rates
- Emergency Response Rates
- Control Deadbands
- ~~SCD~~RTD Basepoints
- Matrix of Generator Shift Factors vs. Security Constraints
- Reserve / Max Gen Pickup Flags
- Step Change Factors.
- Forbidden Region Limits
- Governor Action Bias Factors.

In addition, certain values will be scanned once a second and the six most recent 1-second values will be saved in the ICDA. AGC shall utilize the six 1-second values to generate a smoothed 6-second value for further calculations. These 1-second values are:

- (a) New Scotland frequency
- (b) Tie-line MWs.

Analog Input Filtering

The existing EMS filters all ~~real-time~~Real-Time analog data (i.e., tie-line MWs, generation MWs, and frequency) using two filtering techniques:

- ~~(a)~~ A spike filter delays accepting significant step changes for one six-second scan, discarding the value if the change does not persist (significance limits adjustable for each type of variable)
- ~~(β)~~ A digital filter provides smoothing with the formula:

$$x_i = 0.6*(\text{new input}) + 0.4*x_{i-1}$$

where:

x_i = current filtered value of variable

x_{i-1} = previous value of filtered variable

The capability for additional input filtering, adjustable on an individual variable basis, shall be provided by AGC for future use should this prove necessary.

Frequency Measurement Processing

There are eleven redundant frequency values measured every six seconds throughout the NYCA. Any of these variables can be selected by the dispatcher for the system frequency used in AGC. The primary frequency measurement is the New Scotland 345 kV bus. Automatic Generation Control shall monitor all of the frequency measurements and provide diagnostic information to the dispatcher by generating alarm messages when they are flagged as bad by the EMS. Automatic Generation Control shall also generate an alarm when any of the frequencies are significantly different, implying an islanding condition.

Scheduled Frequency:

Automatic Generation Control shall obtain scheduled frequency from the NYISO Frequency Scheduling function via the ICDA. Whenever scheduled frequency changes, AGC shall use the new value in all subsequent calculations based upon the scheduled start time of the change.

Actual Net Interchange:

Automatic Generation Control shall calculate Actual Net Interchange (ANI) as the algebraic sum of all the tie-line MW values. There are no pseudo tie-lines representing generating units or loads located outside the contiguous NYCA. Automatic Generation Control shall also calculate a filtered Actual Net Interchange (ANI_f) for the Area Control Error calculation defined in Section 6.4.4.

Ramped Desired Net Interchange:

The Interchange Scheduler program determines the Desired Net Interchange (DNI) whenever there is a schedule change. In addition, the dispatcher may change the value of DNI at any time. The following DNI information packet is then provided to AGC in the Avanti database via point data exchange with the mainframe ICDA (previous DNI also available):

1) Desired Net Interchange
2) Ramp Start Time (explicit date and time or indication that start is immediate)
3) Ramp Interval (default 10 minutes)
4) Optional percentage initial step change (see below).

Automatic Generation Control shall continuously monitor the DNI packet in Avanti. Whenever any of the above values change, AGC shall calculate a new ramped Desired Net Interchange that changes linearly to the new DNI value over the Ramp Interval beginning at the Ramp Start Time.

The starting point of the DNI ramp shall normally be either the ANI or the previous value of the ramped DNI, whichever is closer to the new DNI. However, if the current value of ANI is on the opposite side of the new DNI from the old DNI (greater than new DNI if DNI is increasing or less than the new DNI if DNI is decreasing), there will be no ramp. In this case, the value of the new DNI shall become effective immediately without a ramp at the DNI Start Time.

As a dispatcher option, a user adjustable percentage of the change to the new DNI may be taken at the beginning of the ramp, with the remainder of the change ramped linearly over the ramp interval.

Automatic Generation Control shall verify that the rate of change from the old DNI to the new DNI does not exceed a user adjustable rate (typically, 60 MW/min or 600 MWs over 10 minutes); that the start time is not past or too far in the future; that the ramp interval is not too long, nor the initial step too large. Automatic Generation Control shall generate an alarm message to the dispatcher if the new DNI fails these tests. Automatic Generation Control shall limit the change between the new DNI and the old DNI to 10 times the user defined rate.

Automatic Generation Control shall utilize the ramped value of DNI for all calculations involving DNI, including calculations when AGC is SUSPENDED or TRIPPED.

There is no requirement for dynamic interchange schedules that change dynamically in real time (as opposed to quarter-hourly or upon dispatcher entry).

During a system disturbance where ACE becomes very large, the dispatcher may request that ~~SCD~~RTD-CAM operate in the Reserve Pickup or Maximum Generation Pickup mode. During a Reserve / Max Gen Pickup condition, AGC shall stop ramping DNI and hold it constant at the most recent value prior to the initiation of the Pickup. When the Pickup is subsequently deactivated, the value of ramped DNI shall complete the interrupted ramp over the remaining portion of the original ramp interval. When AGC is TRIPPED or SUSPENDED, DNI ramping shall continue as described above.

When AGC is initially changed from OFF or TEST to any other control state, AGC shall set DNI to the final value of the Desired Net Interchange without any ramping.

Unit Limits:

Automatic Generation Control shall always observe a unit's Upper Operating Limit (UOL) and Lower Operating Limit (LOL) for both basepoint changes and regulation. Operating Limits shall not be exceeded unless the dispatcher manually overrides the limit value. If an Operating Limit is changed to a more restrictive value and the unit's actual generation is outside the new value, AGC shall immediately control the unit within the new limit. ~~SCD~~RTD generally observes limits more restrictive than the Operating Limits in determining unit ~~SCD~~RTD basepoints.

Unit Response Rates:

Each unit has up to three bid unit response rates:

- NORMAL Response Rate (NRR) – the expected unit response rate for ~~SCD~~RTD basepoint changes (dispatchable units supplying energy). A unit may specify up to three NORMAL response rates. When multiple NORMAL response rates are defined, each is applied to a portion of the unit's operating range.
- REGULATION Response Rate (RRR) – the expected unit response rate for regulation (units supplying regulation capability)
- EMERGENCY Response Rate (ERR) – the expected unit response rate during Reserve Pickup and Maximum Generation Pickup modes (units supplying reserve capability for reserve pickup and all dispatchable units for max gen pickup)

For units supplying regulation, if RRR differs from the capacity-weighted NRRs, the total expected response rate is the maximum of the capacity-weighted NRRs and RRR. For units supplying reserve, ERR must be greater than or equal to the capacity-weighted NRRs.

Response rates are not calculated or based on unit test results but are specified by a unit's owner in the bidding process. They are assumed to be constant over the unit's entire operating range in both directions.

Ramped ~~SCD~~RTD Basepoints:

Under normal conditions ~~when Reserve / Max Gen Pickup is not activated, SCD~~RTD calculates new ~~SCD~~RTD basepoints for all MANUAL, BASE and REGULATE units in the NYCA ~~(nominally every~~5 minutes~~)~~ and passes these values to AGC. ~~SCD~~RTD also sends the basepoints directly to these units to provide an advanced indication of expected unit loading.

Just prior to the start of each hour, the execution of ~~SCD~~RTD is deferred until 30 seconds after the hour. ~~Security Constrained Dispatch~~Real-Time Dispatch runs at that time to calculate proper new basepoints for all units that are scheduled hourly.

Automatic Generation Control shall have access to both the current and previous values of unit basepoints. Each set of basepoints includes a single time stamp to indicate when ~~SCD~~RTD calculated these values. Whenever AGC detects a change in the time stamp of the current basepoints, AGC shall calculate new Ramped ~~SCD~~RTD Basepoints (RBP) for all units.

The starting value for each basepoint ramp shall be determined differently for regulating units and non-regulating units:

- (a) Regulating Units – the starting value for the basepoint ramp shall be the old basepoint calculated during the previous execution of ~~SCD~~RTD (modified if necessary for hydro units as described in Section 6.3.10,

Minimize Hydro Unit Deviation From
Water Schedule)

- (b) Non-Regulating Units – the starting value for the basepoint ramp shall be determined by the unit's actual generation in relation to the old basepoint calculated during the previous run of ~~SCD~~RTD and the new ~~SCD~~RTD basepoint, as follows

1) If Actual Generation is below the old basepoint for a basepoint increase or above the old basepoint for a basepoint decrease, the Ramped ~~SCD~~RTD Basepoint shall begin the ramp from the old basepoint value and shall reach the new ~~SCD~~RTD basepoint value in exactly 5 minutes, with the value changing every AGC program execution

2) If Actual Generation is between the old and new basepoints, the Ramped ~~SCD~~RTD Basepoint shall begin from the value of the Actual Generation and reach the new ~~SCD~~RTD basepoint in exactly 5 minutes, with the value increasing every AGC program execution

3) If Actual Generation is above the new basepoint for a basepoint increase or below the new basepoint for a basepoint decrease, the Ramped ~~SCD~~RTD Basepoint shall be set immediately to the value of the new basepoint.

The value of the Ramped ~~SCD~~RTD Basepoint will be included in the determination of each unit's Unit Desired Generation (UDG).~~ described below in Section 6.6, Unit Desired Generation.~~

~~When SCDRTD runs more frequently than every five minutes (minimum of 2.5 minutes after the previous run), the new SCDRTD basepoint shall be achieved in exactly 5 minutes from the time of the new SCDRTD execution and the starting point of the ramp shall be determined as above. If the interval between SCDRTD executions is greater than five minutes, all Ramped SCDRTD Basepoints shall be held at the value of their new SCDRTD basepoints reached in five minutes until such time as SCDRTD runs again.~~

Automatic Generation Control is not required to check whether or not the ramp rate to the new ~~SCD~~RTD basepoint for any unit exceeds the Normal or Emergency Response Rates for that unit. However, AGC shall ensure that the new basepoint observes the unit's Upper and Lower Operating Limits. AGC shall also restrict new basepoints to a user adjustable maximum basepoint change limit for each generator.

All units that are NOT "self-committed fixed" are expected to respond to a reserve pickup 10-minute basepoint at its emergency response rate as bid. If the unit exceeds the given basepoint established by RTD-CAM or Reserve Pickup is deactivated, whichever occurs first, it will be paid for the overgeneration. However, the unit must return to its RTD basepoint, which will be consistent with the LBMP, within three RTD intervals (15 min) following termination of the reserve pickup. The unit will also be paid for overgeneration during that grace period.

On Control with or without a reserve award:

An on-control unit providing 6 second AGC regulation is expected to respond to a reserve pickup 10-minute basepoint at its stated response rates bid. If the unit exceeds the given basepoint within the reserve pickup, it will be paid for the overgeneration. However, the unit must return to its RTD/AGC basepoint, which will be consistent with the LBMP, within three RTD intervals following termination of the reserve pickup. The unit will be paid for overgeneration during the 3-RTD interval grace period.

~~When Reserve Pickup is activated (system-wide Reserve Pickup Flag set), a unit that has been selected to supply Reserve capability (individual unit Reserve Pickup Flag set) will be requested to raise generation at its EMERGENCY response rate until it reaches its SCDRTD basepoint or until Reserve Pickup is deactivated, whichever occurs first. Units not supplying Reserve capability will not be affected by the activation of Reserve Pickup. When Reserve Pickup is deactivated, AGC shall set the unit's basepoint equal to its actual generation until SCDRTD establishes new basepoints.~~

~~An additional pickup mode, Maximum Generation Pickup, is identical to Reserve Pickup except that all dispatchable generation is expected to move at emergency response rates.~~

~~Ramped SCDRTD Basepoints shall be calculated as long as AGC is either ACTIVE, SUSPENDED, or TRIPPED. When AGC is initially changed from OFF or TEST to any other control state, AGC shall check whether SCDRTD has run recently. If not, AGC shall request an SCDRTD execution and wait for SCDRTD to calculate new unit basepoints. When recent SCDRTD basepoints become available, AGC shall initialize the values of the old basepoints for all units to the values of their actual generation before calculating new Ramped SCDRTD Basepoints.~~

Minimize Hydro Unit Deviation From Water Schedule:

Automatic Generation Control shall bias the ramped basepoints for regulating hydro units to allow them to stay close to their scheduled water release profile. For example, if during NYCA system morning load pickup, a regulating hydro unit regulates above its ~~SCD~~RTD basepoint much more often than below it, it will release too much water. Automatic Generation Control shall accumulate the net amount of regulation energy $\Sigma(UDG_i - RBP_i)$ every control cycle between midnight and midnight for each regulating hydro unit and, whenever the magnitude of regulation energy exceeds a user adjustable limit for each unit, bias the unit's ~~SCD~~RTD basepoint by an individually adjustable fixed offset in the direction to reduce the accumulated regulation energy. The regulation energy accumulation for a unit shall be reset to zero whenever the AGC control state or the unit control mode changes and at midnight.

~~[***Note:*** *This special handling of the valuable asset of water at hydro units will have to be approved by GIRT. The AGC WG should decide whether or not to request this approval.]*~~

Determination of AGC Control State, Area Control Error, and Area Requirement

The AGC function shall determine its Control State based upon conditions in the NYCA and upon dispatcher entry. The calculation of Area Control Error, filtered Area Control Error, and Area Requirement shall be the next steps in defining control requirements for generating units involved in regulation for the NYCA.

AGC Control States:

The AGC function shall operate in one of the following AGC Control States:

- ACTIVE – All AGC functions operational
- SUSPENDED – Inputs processed, desired net interchange (DNI) ramped, ACE calculated, and UDG calculations for regulating units temporarily changed to follow ramped ~~SCD~~RTD basepoints only (holding the last deviation from basepoint due to regulation)
- TRIPPED – Functionally similar to SUSPENDED, AGC goes to TRIP state after being SUSPENDED for a user adjustable period of time or upon dispatcher command. In addition, the regulation component shall be gradually removed from the values of UDG for regulating units (see Section 6.6.2.2, UDG While AGC is SUSPENDED or TRIPPED).
- OFF – AGC not operational; all UDGs held constant.
- TEST – AGC functions operational except UDGs are displayed and saved but not sent to units (OFF state telemetered to generating units).

Transition to/from TEST or to/from OFF and between ACTIVE and TRIPPED shall be under dispatcher control only; transitions between ACTIVE and SUSPENDED shall be automatic based upon the occurrence and duration of any of the conditions defined below in Section 6.4.1.1, AGC Suspension, as well as under dispatcher control.

The SUSPENDED state shall only be reached from the ACTIVE state. When the condition causing the SUSPENDED state is relieved within a user adjustable period, either on its own or by means of dispatcher manual override, transition back to ACTIVE shall occur automatically. When the SUSPENDED state is not relieved within this period, an automatic transition of AGC control state from SUSPENDED to TRIPPED shall occur. The dispatcher may also transfer AGC to TRIPPED at any time.

The AGC Control State shall be transmitted to all generating units and to the ~~TP~~TOs either every 6 seconds or upon change.

AGC Suspension:

AGC shall be automatically suspended upon occurrence of any of the following conditions that are sustained for longer than a user adjustable period of time:

- Excessive ACE (separate limit in each direction)
- Invalid frequency telemetry
- Invalid telemetry from any significant tie-line (i.e., last valid value greater than a user adjustable limit per tie-line in each direction)
- Invalid telemetry from any of a predefined set of significant generators.

Failure of input validity shall be determined when a value is outside its Reasonability Limits, when the status of the input is BAD, or the input telemetry is marked as FAILED in the system database. However, AGC shall not be suspended upon the occurrence of large frequency excursions.

Upon AGC suspension, the dispatcher shall be notified and the calculation of UDGs shall be modified as described below in Section 6.6.2.2, UDG While AGC Is SUSPENDED or TRIPPED.

AGC Trip:

Automatic Generation Control shall be automatically tripped when AGC has been suspended for more than a user adjustable time period or upon dispatcher direction. Upon AGC trip, the dispatcher shall be notified and the calculation of UDG shall be modified as described in Section 6.6.2.2, UDG While AGC Is SUSPENDED or TRIPPED.

Sign Conventions:

The sign conventions for AGC shall be as follows:

1) Power Flow INTO the NYCA is POSITIVE (+)
2) Net Interchange (both Desired Net Interchange (DNI) and Actual Net Interchange (ANI)) INTO the NYCA is POSITIVE (+)
3) For Inadvertent Interchange, defined as (DNI – ANI), POSITIVE (+) indicates excess generation
4) Frequency Bias Coefficient is NEGATIVE (–)
5) POSITIVE (+) ACE indicates excess generation and requires generation to DECREASE.

ANI Filtering:

The AGC function shall provide a filter for total actual net interchange with user adjustable tuning coefficients. The result of this filter will be denoted ANI_f. The filter shall operate as follows:

$NI_I = * ANI + (\beta * NI_{i-1}$
Where $= ½ANI – NI_{i-1}½/K$
$\beta = 1 - \alpha$
κ = Filter Constant
Also, if $\alpha > 1$, $NI_i = ANI$.

Area Control Error Calculation:

Automatic Generation Control shall calculate both unfiltered Area Control Error (ACE) for the purpose of NERC compliance calculations and filtered Area Control Error (ACE_f) in order to develop the control requirement to minimize NYCA deviation from the scheduled values of frequency and net interchange. The value of ACE shall be determined as follows:

$$ACE = [(DNI – IPS) – (ANI + NIO)] – [\beta_f * (F_A - F_S)]$$

The value of filtered area control error (ACE_f) shall be determined as follows:

$$ACE_f = [(DNI – IPS) – (ANI_f + NIO)] – [\beta_f * (F_A - F_S)]$$

Where:

- ACE = Unfiltered Area Control Error
- ACE_f = Filtered Area Control Error
- DNI = Desired Net Interchange
- ANI = Unfiltered Actual Net Interchange
- ANI_f = Filtered Actual Net Interchange
- IPS = Inadvertent Payback Setter (see below)

- NIO = Net Interchange Offset (includes meter error correction) (see below)
- βf = Frequency Bias Coefficient (currently -2880 MW/Hz)
- FA = Actual Frequency
- FS = Scheduled Frequency (default value = 60.0 Hz)

As a selectable alternative to the above calculation of ACE_f, the Actual Net Interchange shall not be filtered but instead the raw value of unfiltered ACE shall be filtered. This filtered raw ACE may be utilized instead of ACE_f.

In either case, filtering shall be provided such that load trends, interchange schedule changes, and frequency deviations are recognized, but fast, zero-mean, randomly varying changes in ACE are removed and unnecessary unit control is minimized. The filtering algorithm shall not delay AGC response to controllable ACE excursions nor respond to fast transient excursions. Nonlinear filtering techniques or statistical methods are acceptable.

Also in either case, the raw value of ACE, which includes the spike filtering and simple smoothing for each tie line input to exclude transient telemetering problems, shall only be used for NERC Performance Monitoring purposes.

ACE Calculation Modes:

Automatic Generation Control shall normally operate in Tie-Line Bias Control Mode using the above formula to calculate ACE_f. Operation in either Constant Net Interchange Mode [$ACE_f = (DNI - IPS) - (ANI_f + NIO)$] or Constant Frequency mode [$ACE_f = -\beta_f * (F_A - F_S)$] shall be selected by the dispatcher when necessary.

There is no requirement for special automatic inadvertent or time error correction modes. Inadvertent interchange corrections will be implemented by creating firm transactions that affect DNI. Time error correction will be implemented via dispatcher changes to the value of Scheduled Frequency, typically to 59.98 or 60.02 Hz, either of which shall be selectable as default values without explicit numeric entry.

In the event of islanding of the NYCA, the dispatcher shall be able to select Constant Frequency mode and place AGC in the ACTIVE control state to control a single control area that includes those generators specified by ~~SCD~~RTD with electrical connectivity to the NYISO Control Center.

Inadvertent Payback Setter:

The Inadvertent Payback Setter (IPS) component of ACE is used to payback energy under the specific cases of NPCC shared activation of reserve or unilateral paybacks under NERC rules. IPS is set manually by the dispatcher.

Net Interchange Offset:

The Net Interchange Offset (NIO) component of ACE is used to correct for differences between MW and MWh metering. NIO is calculated by AGC every 6 seconds as the algebraic sum of an array of values in the ICDA that lists the difference between the hourly MWh meter reading and the integrated instantaneous MW value for each tie-line for the previous hour.

ACE Deadband:

When the magnitude of raw ACE falls within a user adjustable deadband, the calculated value of ACE_f shall be set to zero.

Area Requirement:

The Area Requirement (AR) shall be determined from ACE_f using a control scheme that incorporates both ACE_f and the integral of ACE_f. The integral term shall increase the Area Requirement when the magnitude of ACE_f is moderate and persists at nearly a constant value. The integral term shall be reset whenever:

1) ACE_f is changing more than a user adjustable amount per AGC cycle
2) ACE_f magnitude falls within its user adjustable deadband
3) ACE_f crosses zero
4) ACE_f magnitude exceeds a user adjustable limit
5) AGC control state changes
6) Change in dispatcher selection of either integral term or ACE biasing (defined below).
    i) The integral term shall not result either in overshoot when regulating units are moving to correct a large ACEf or cause AR to windup when AGC is not ACTIVE. Optionally, AR shall also take into account the total anticipated unit response to previous control actions.
    ii) Note that the use of the term "Area Requirement" in this Specification differs from the traditional use of the term, where area requirement is equivalent to negative area control error.

ACE Biasing:

An ACE Biasing term shall be provided in the event that the AR calculation defined above does not result in appropriate response to ACE_f. In this case, AR shall be determined from ACE_f using an ACE Biasing term instead of the integral of ACE_f. The ACE Biasing term shall add to or subtract from ACE_f a value whose magnitude increases linearly (up to a limit) when the magnitude of ACE_f remains outside a user adjustable limit for more than a user adjustable time period. The bias shall decrease at a user adjustable rate when the magnitude of ACE_f returns within another limit for more than a user adjustable time period. Setting AR equal to ACE_f plus the ACE Biasing term in lieu of ACE_f plus the integral of ACE_f, or setting AR equal to ACE_f, shall be selectable by the dispatcher.

Feedforward Control:

The AGC function shall reduce unnecessary control action at regulating units by compensating for unit response lag with feedforward control. The feedforward logic shall anticipate response to prior control actions and introduce appropriate compensation while waiting for regulating units to respond. Individual units need not be modeled separately but regulating units will be considered as a single lumped unit with a single lag.

The vendor shall recommend a feedforward control method that should consider AGC control outputs over (at least) the previous 5 control cycles and take into account the removal of control windup from Unit Desired Generation values (described in Section 6.6.4, Remove Windup in Previous Values of UDG).

Predictive Features:

The AGC algorithm is not required to incorporate predictive features for load or interchange. The ~~SCD~~RTD function incorporates a 5-minute load forecast, the anticipated change to DNI, and units starting up or shutting down in determining the basepoints for all units.

Select Specific Generating Units for Regulation

Although the bid Regulation Response Rates could be used to distribute the Area Requirement to all regulating units every AGC cycle, a more sophisticated selection of specific generating units for regulation shall be made to achieve a variety of objectives. These objectives include improvement in overall system responsiveness to AR, observing security constraints, keeping regulating units operating close to their (ramped) ~~SCD~~RTD basepoints, and reducing the frequency and amount of loading changes requested for each unit.

To achieve these objectives, units shall be selected for regulation with a 6-step process:

1) Establish unit control mode (e.g., OFFLINE, MANUAL, BASE, REGULATE or TEST).
2) Calculate the preliminary effective response rate actually available from each regulating unit taking into account its bid Regulation Response Rate, unit operating limits, and the direction of basepoint ramping relative to the direction to reduce AR.
3) Rank regulating units in order of preference for use this control cycle based upon security constraints, preliminary effective response rate, the magnitude of AR, the deviation of unit actual generation from its ramped ~~SCD~~RTD basepoint, direction of ~~SCD~~RTD ramp to reduce/increase AR, whether the unit is stopped or already moving in the direction to increase or decrease AR, and how often the unit has been selected previously for regulation.
4) Calculate the magnitudes of total regulation available using increasing numbers of regulating units.
5) Determine the total amount of regulation required to reduce AR to zero in a reasonable period of time.
6) Select the specific regulating units in order of rank necessary to provide the total amount of regulation required.

Unit Control Modes:

Automatic Generation Control shall support generators in various unit control modes. AGC shall derive (as a minimum) the following unit control modes, which are derived from the three unit operating status flags received in ~~real-time~~Real-Time from ~~TP~~TOs associated with each generating unit and from dispatcher entries:

1) UNAVAILABLE – Unit offline with the unit breaker tripped, unavailable for reserve contribution, and not considered by AGC (On-Line flag reset)
2) OFFLINE/AVAILABLE (OFFLINE) – Unit offline with the unit breaker tripped, available for reserve pick-up, but not considered by AGC (On-Line flag reset)

3) OFF-DISPATCH (MANUAL) – Unit breaker closed and unit manually controlled in the field by unit personnel based upon its ~~SCD~~RTD recommended basepoint sent every 5 minutes (includes hourly schedule changes and the
periods during a unit's initial ramp up to minimum generation and final ramp down prior to shut down according to a ramping profile (On-Line flag set, On-Dispatch Flag reset)
4) ON-DISPATCH/NON-REGULATING (BASE) – Unit breaker closed and unit automatically controlled by AGC to its ramped ~~SCD~~RTD basepoint without contribution to regulation (On-Line & On-Dispatch flags set, On-Control flag reset)
5) ON-DISPATCH/REGULATING (REGULATE) – Unit breaker closed and unit automatically controlled by AGC to the combination of its ramped ~~SCD~~RTD basepoint and its regulation requirement (On-Line, On-Dispatch & On-Control flags set)
6) TEST – Unit breaker closed and unit automatically controlled using NYISO dispatcher-entered UDG (On-Line & On-Dispatch flags set plus dispatcher entry to override On-Control flag).

The dispatcher may change the derived unit control mode as follows:

(a) REGULATE to BASE
(b) REGULATE or BASE to MANUAL or TEST
(c) TEST to/from MANUAL.

The unit control mode currently in effect shall be transmitted to each of the generating units either periodically or upon change.

Preliminary Effective Regulation Response Rates:

The next step in selecting units for regulation during a particular AGC control cycle is the determination of their preliminary effective regulation response rates (PERRRs). PERRRs are the unit response rates actually available from regulating units. (The term "preliminary" implies that subsequent adjustments will be made to these values defined in Section 6.5.10, Select Regulating Units and Calculate Final ERRRs.)

PERRRs are transient and, every control cycle, may vary from the values of the Regulation Response Rates (RRRs) bid for those units. PERRR values depend upon whether the regulating units are already being ramped to new ~~SCD~~RTD basepoints that tend to increase or decrease AR and are also affected when units reach their operating limits.

For a regulating unit not at its operating limit and already ramping in a direction to decrease AR, its effective (additional) regulating response rate shall be the difference between its bid RRR and its ramp rate (ERRR = RRR-|BPR|). If its basepoint ramp rate exceeds RRR, there is no additional response rate available and ERRR shall be zero (see Figure 6-8, Effective Regulation Response Rates, Case 1).

Alternatively, if a regulating unit is already ramping in a direction to increase AR, AGC shall have the option of stopping the basepoint ramp (PERRR = |BPR|) and, possibly, reversing the unit to move it at its RRR in the opposite direction (PERRR = RRR+|BPR|) (see Figure 6-9, Effective Regulation Response Rates, Case 2).

If there is no basepoint ramp, the PERRR shall equal its RRR.

When a regulating unit reaches an operating limit, its PERRR shall be determined in a similar fashion. However, when the limit blocks unit movement for regulation, ramping, or both, the value of PERRR is affected depending upon the relative direction of its basepoint ramp and its regulation requirement.

These conditions may be summarized as follows: (see Figure 6-10, ERRRs & UDG):

Unit Not At Limit

BPR & AR move unit in same direction: PERRR = RRR-|BPR| (or 0 if |BPR|>RRR)
BPR & AR move unit in opposite directions: PERRR = |BPR| (possibly RRR+|BPR|)
BPR = 0: PERRR = RRR

Unit At Limit

BPR & AR both move unit beyond limit: PERRR = 0 (no movement possible)
BPR & AR both move unit in from limit: PERRR = RRR-|BPR| (or 0 if |BPR|>RRR)
BPR moves unit beyond limit & AR opposite: PERRR = |BPR| (possibly RRR+|BPR|)
BPR moves unit in from limit & AR opposite: PERRR = |BPR| (stop ramp)

Composite Priority Factors:

When the magnitude of AR is small or moderate, AGC shall not distribute the control requirement to all the regulating units available but shall use units deemed best during that control cycle. In order to select the most appropriate regulating units for control, AGC shall rank each unit in order of preference based upon a Composite Priority Factor (CPF) determined, separately for each regulating unit, on the following priority factors:

(a) Deviation of the unit~~’~~s desired generation calculated last AGC cycle from the unit’s current ramped ~~SCD~~RTD basepoint
(b) Direction of the unit’s ~~SCD~~RTD basepoint ramp to either increase or decrease AR
(c) Whether or not the unit’s actual generation is changing or the unit is stopped, and
(d) How often the unit has recently been selected for regulation.

Each of these priority factors shall be calculated as a numeric value from 0 to 1.0 and then be weighted with a user adjustable priority factor coefficient common to all units. Each priority factor shall also be enabled or disabled based upon the magnitude of AR, compliance with the NERC Control Performance Standards, and/or at dispatcher option. The weighted and enabled factors shall be added together to generate the CPF for each regulating unit.

Automatic Generation Control shall be sufficiently flexible to permit the addition of other CPF priority factors.

Deviation from Ramped ~~SCD~~RTD Basepoint Priority Factor:

A regulating unit that is controlled away from its ramped ~~SCD~~RTD basepoint may eventually approach an operating limit. In order to maintain regulating margin in both the raise and lower directions, it is preferable to operate this unit close to its basepoint. Units that are farthest from their ramped basepoints and can be moved towards those basepoints in a direction to decrease AR shall have a higher priority factor than other units. The size of the CPF shall be inversely proportional to the Regulation Response Rate of the unit so that units that move quickly away from their basepoints will not be assumed to be abnormally far from their basepoints relative to units that move more slowly. This element shall also be normalized to keep the element in proportion to other elements in CPF. The Basepoint Deviation Priority factor shall be calculated as follows:

Deviation = $((UDG_{t-1} – RBP)*(SIGN(AR)) / (RRR/\Sigma RRR_i)$
Normalized Deviation = (Deviation – Lowest Deviation) / (Highest Deviation – Lowest Deviation)
Weighted Deviation = Normalized Deviation * C_D
Basepoint Deviation Priority Factor = Weighted Deviation * [Enable (1) or Disable (0)]

Where:

UDG_{t-1} = Previous UDG (see Section 6.6, Unit Desired Generation)
RBP = Ramped ~~SCD~~RTD Basepoint
AR = Area Requirement
RRR = Regulation Response Rate
ΣRRR_i = Sum of RRR for all REGULATE units
Lowest Deviation = Lowest algebraic value of Deviation (may be negative)
Highest Deviation = Highest algebraic value of Deviation
C_D = Deviation coefficient (common for all units)

Direction of Unit Ramping Priority Factor:

It may be desirable (and easier) to speed up units already ramping to a new ~~SCD~~RTD basepoint in the direction that decreases AR rather than to control units that are not ramping or that are ramping to a basepoint that increases AR. Units that are already ramping in a direction to increase AR may be more desirable to slow down or stop ramping than to control a unit not currently ramping. The Ramping Direction Priority Factor attempts to quantify these preferences. The Ramping Direction Priority factor shall be calculated as follows:

Ramp Index =
1.0 if basepoint ramp decreases AR
0.5 if basepoint ramp increases AR, or
if either ramp rate or AR is 0

Weighted Ramp Index = Ramp Index * C_R

Ramp Direction Priority Factor = Weighted Ramp Index * [Enable (1) or Disable (0)]
where:

C_R = Ramp Index coefficient (common for all units)

Unit Moving Priority Factor:

It may be desirable to utilize units already moving for regulation rather than units that are stopped. If so, the Unit Moving Priority Factor will raise the priority of moving units. The Unit Moving Priority factor shall be calculated as follows:

Moving Index =

1.0 if unit actual generation has changed by more than an individually user adjustable limit per unit over the past n control cycles

0.0 if unit actual generation has not changed

Weighted Moving Index = Ramp Index * C_M

Unit Moving Priority Factor = Weighted Moving Index * [Enable (1) or Disable (0)]

where:

C_M = Moving Index coefficient (common for all units)

Unit Usage Priority Factor:

It may not be desirable to use some regulating units often and others infrequently. The Unit Usage Priority Factor gives preference to units that have not been used for regulation recently. The Unit Usage Priority factor shall be calculated as follows:

Usage = Number of times a unit has been selected for regulation in the past m control cycles

Normalized Usage = (Highest Usage – Usage)/(Highest Usage – Lowest Usage)

Weighted Usage Index = Normalized Usage * C_U

Unit Usage Priority Factor = Weighted Usage Index * [Enable (1) or Disable (0)]

where:

C_U = Usage Index coefficient (common for all units)

Enable/Disable Priority Factors:

Each of the above priority factors shall be enabled or disabled based upon the magnitude of AR, whether or not the NYCA is operating in compliance with the NERC Control Performance Standards, and/or based on dispatcher entry.

Whenever the magnitude of AR exceeds a user adjustable limit for each category of priority factor, that priority factor shall be temporarily set to zero. Similarly, whenever the NYCA is not operating in compliance with the NERC Control Performance Standards as defined below in Section 6.5.8, Calculate NERC Compliance Criteria, each of the priority factors may be disabled. Finally, the dispatcher shall be able to enable or disable any individual priority factor separately for each regulating unit.

Fast-Response Units:

Regulating units with very fast response rates shall be controlled back to their basepoints once they reach an operating limit as long as the magnitude of AR remains small (see Section 6.6.5, Fast-Response Units Return to Basepoint, below). Fast-response units being controlled back to their basepoints shall have their composite priority factor set to zero to avoid being selected for regulation. Fast-response units shall be identified as having a RRR greater than a user adjustable limit.

Security Constraints:

The ~~SCD~~RTD function establishes unit basepoints that meet the twin objectives of meeting forecasted system load and relieving security constraints imposed by both real and contingency overloads. In order that AGC not undo the efforts of ~~SCD~~RTD to maintain system security, AGC shall take security constraints into account when ranking regulating units to minimize AR.

To facilitate this process, ~~SCD~~RTD can provide security constraint information to AGC using two possible alternatives – dynamic unit operating limits and generator shift factors.

Under the first alternative, ~~SCD~~RTD will calculate dynamic unit operating limits for each regulating unit. These limits, inside or equal to the Upper and Lower Operating Limits for each regulating unit, will constrain AGC from making active security constraint violations worse.

Alternatively, there exists already within the NYISO computer system a separate process that generates and maintains a matrix of generator shift factors (GSFs) for every generator vs. every predefined security constraint in the NYCA. These shift factors define the sensitivity of each generator to potential constraints on system facilities, along with an indication of the direction of power flow. The matrix will be recalculated for every significant change in network topology by the separate NYISO process. Every 5 minutes, ~~SCD~~RTD will identify to AGC those constraints that are active in the NYCA (including direction) and AGC shall avoid moving units in a manner that would make active constraints worse.

For each generator in REGULATE control mode (i.e., specific columns in the GSF matrix), AGC shall identify the shift factors (i.e., elements on the active constraint rows in the GSF matrix) that correspond to "active" constraints. Depending on the sign and magnitude of the identified shift factors, AGC shall then determine whether the associated generators should be prevented from regulating in the raise direction, in the lower direction, or in either direction.

Only GSFs whose magnitudes are greater than an adjustable GSF threshold will be considered as "significant" for this process. The GSF threshold shall be calculated according to the following formula:

> GSF Threshold = $k_1 - k_2 * ½AR½$, where k_1 and k_2 are user adjustable (positive) coefficients for each generator.

If all the "significant" GSFs for a regulating unit are positive, the unit will be not be used to regulate in a raise direction during that AGC program execution. If all the "significant" GSFs for a unit are negative, the unit will be not be used to regulate in a lower direction. If some "significant" GSFs are positive and some are negative, the unit will not be used for regulation in either direction, depending upon the magnitudes of these factors. If no GSFs are "significant,"~~,~~

there will be no restrictions on regulating unit movement. Depending upon the control requirement to raise or lower the regulating unit, AGC shall either set the Composite Priority Factor to zero or leave it unchanged.

The effect on system operation of preventing regulating units from making constraint violations worse is the reduction of regulation capability in one or both directions. Depending upon the magnitude of AR and the response rates of the remaining units, AGC may not be as aggressive in minimizing AR in the presence of security constraints. If AR becomes large and/or AGC response is not sufficiently aggressive, an alarm message shall be issued and the dispatcher may select additional regulating units based on their location in the network and/or shall be disable one or more security constraints for consideration in this process or choose to disable all security constraints on AGC.

Create Ordered List of Regulating Units:

Based upon the magnitude of the Composite Priority Factor (CPF) for each regulating unit, AGC shall create an ordered list of units available for regulation this control cycle ranging from the most desirable to the least desirable unit. Units with zero CPFs shall not be included on the list.

Create List of Total Available Regulation Response Rates:

AGC shall calculate the Total Available Regulation Response Rate (TARRR) for each combination of regulating units on the list of units available for regulation this control cycle. Beginning with the Effective Regulation Response Rate (ERRR) for the most desirable unit, this list will consist of increasing TARRRs for increasing numbers of less desirable units one at a time up to and including the TARRR for all units on the list.

Determine Required Regulation Response Rate:

AGC shall calculate the Required Regulation Response Rate (RRRR) this AGC cycle as a function of the magnitude of AR. The RRRR is a method of expressing the desired number of control cycles it will require to reduce |AR| to zero.

RRRR shall be determined from a calculation (e.g., RRRR proportional to |AR|), RRRR calculated from a segmented curve based upon whether |AR| is small, medium or large, or RRRR determined from a table lookup function). The goal of determining RRRR in this fashion is to vigorously respond to large values of |AR| while not moving units unnecessarily when |AR| is small.

Calculate NERC Compliance Criteria:

AGC shall determine the current and projected compliance of the NYCA with the NERC Performance Standard performance measures, CPS1 and CPS2, and the NERC Disturbance Control Standard (DCS).

AGC shall calculate current compliance with CPS1 and CPS2 in accordance with the Performance Standard Training Document and the Control Performance Criteria Training Document in NERC's Operating Policies. AGC shall calculate a CPS1 Compliance Factor and a CPS2 Compliance Factor that are functions of unfiltered ACE times frequency deviation and of |ACE|, respectively. When this compliance is poor over a user adjustable period of time, or is projected to be poor over the full accounting period based upon performance so far, AGC shall periodically issue an alarm message to the dispatcher, adjust the Composite Priority Factors defined in Section 6.5.3 above, and increase the Required Regulation Response Rate (RRRR) by a user adjustable amount.

AGC shall also detect disturbance conditions based upon NERC criteria and determine projected compliance with DCS over the ten minutes following the disturbance. AGC shall issue an alarm message to the dispatcher when a disturbance is detected and when the value of ACE returns either to zero or to its pre-disturbance value, as appropriate. When compliance is projected to be poor, AGC shall issue an alarm message to the dispatcher at a user adjustable periodicity and shall also increase the Required Regulation Response Rate (RRRR) as needed until ACE returns to either zero or its pre-disturbance value.

Minimize Unit Control Activity:

In order to reduce the amount of control issued to regulating units, AGC shall determine whether or not any regulation control changes should be issued this AGC cycle. This determination shall be based upon several factors, including how recently changes were issued, the magnitude of AR, the Required Regulation Response Rate, the NERC Compliance Criteria, and/or the net magnitude of the anticipated control error changes requested from regulating units but not yet acted upon.

Select Regulating Units & Calculate Final ERRRs:

Based upon the Required Regulation Response Rate (RRRR) this control cycle, AGC shall select the appropriate number of units for regulation. For example, if RRRR can be satisfied by the highest priority five units out of eight units available, the AR shall be distributed to these five units as defined in Section 6.6, Unit Desired Generation, below. The Unit Usage Counter used to determine Unit Usage Priority Factor (Section 6.5.3.4) shall be incremented for units selected for regulation and the Effective Regulation Response Rates (ERRRs) set to zero for all units not selected for regulation.

If insufficient regulation response rate is available from all regulating units with non-zero CPFs, AGC shall invoke additional regulation response rates from regulating units ramping in the opposite direction. Up until this determination, the ERRR for these units represented simply stopping them from ramping (ERRR = |BPR|). However, in cases of insufficient TARRR, these units will be not only stopped, but will be reversed and the full Regulation Response Rate in the opposite direction shall be utilized. AGC shall change their ERRRs to include RRR (ERRR = RRR+|BPR|). The additional regulating response rate from these units shall be invoked one at a time in order of their CPFs for this purpose until RRRR is satisfied. The value of TARRR will be updated with each increase in ERRR. All other selected regulating units shall have their ERRR set to the values of PERRR determined previously (see Section 6.5.2 & Figure 6-10, ERRRs & UDG).

Unit Desired Generation

AGC shall calculate Unit Desired Generation (UDG) for all units on control in the NYCA. UDG shall be determined in accordance with the following four steps:

(a) Initialization and remove control wind-up, if any, in previous values of UDG
(b) Calculate the value of UDG
(c) Add an initial step change if required
(d) Augment the UDG with governor action bias, if necessary.

UDG Initialization and Removal of Control Wind-Up:

When AGC control status first changes from OFF or TEST to TRIPPED or ACTIVE, AGC shall initialize the previous value of UDG for every unit to equal the value of its current actual generation.

For regulating units attempting to reduce AR to zero, the UDG values will always be ahead of unit actual generation since these units cannot follow UDG precisely. If AR suddenly returns close to zero or changes sign, the UDGs for these units will temporarily continue to request generation changes that are no longer required. Consequently, the previous value of UDG for a regulating unit with control windup shall be set either to the value of its current actual generation or its ramped ~~SCD~~RTD basepoint, which ever is closer to the previous UDG. Windup in a regulating unit UDG value shall be assumed when AR returns within its deadband or changes sign and the UDG is either greater than or less than both its actual generation and its ramped basepoint (see Figures 6-11, 6-12, & 6-13, Removal of Control Windup, Cases 1, 2 & 3).

Calculate UDG:

AGC shall determine the value of UDG for all MANUAL, BASE and REGULATE units. The UDG for any unit shall not exceed its operating limits (UOL or LOL) (see Section 6.3.7). UDG shall be calculated to the nearest tenth of a MW. The method of calculating UDG shall depend upon whether AGC is ACTIVE/TEST, SUSPENDED/TRIPPED, or OFF.

UDG While AGC Is ACTIVE or TEST:

While AGC is in the ACTIVE or TEST control state, UDGs shall be calculated based upon their previous UDGs, their basepoint ramp rates, and, for regulating units, their ERRR values. The only difference between ACTIVE and TEST is that when AGC is in TEST control state, the final UDG values are not sent to the generating units.

The specific determination of UDG for each unit depends upon its unit control mode:

1) OFFLINE: No UDG is calculated
2) MANUAL & BASE: UDG shall equal the previous value of UDG calculated last AGC program execution plus the delta ramped ~~SCD~~RTD basepoint. The delta ramped ~~SCD~~RTD basepoint is calculated whenever the basepoint changes (see Section 6.3.9, Ramped ~~SCD~~RTD Basepoints, above):

$$UDG_i = UDG_{i-1} + \Delta RBP_i$$

where:

UDG_i = Unit Desired Generation for regulating unit i

UDG_{i-1} = Previous value of UDG for regulating unit i
ΔRBP_i = Delta ramped ~~SCD~~RTD basepoint for regulating unit i

The dispatcher shall have the option of disabling basepoint ramping of all non-regulating units when the basepoint ramp is in the direction that increases |AR| and |AR| is greater than a user adjustable limit.

3) REGULATE (Unit Selected for Regulation This Cycle): UDG equals the previous value of UDG plus the delta ramped ~~SCD~~RTD basepoint less ERRR times the sign of AR.

$$UDG_i = UDG_{i-1} + \Delta RBP_i - (ERRR_i/10)*SIGN(AR)$$

where:

$ERRR_i$ = Effective Regulation Response Rate for Regulating Unit I
$ERRR_i/10$ = The amount of $ERRR_i$ available in 6 seconds ($1/10^{th}$ of a minute)
AR = Area Requirement

4) REGULATE (Unit Not Selected for Regulation This Cycle): UDG shall equal the previous value of UDG calculated last AGC program execution plus the delta ramped ~~SCD~~RTD basepoint:

$$UDG_i = UDG_{i-1} + \Delta RBP_i$$

The dispatcher shall have a separate option (separate from non-regulating units) to disable basepoint ramping of all non-selected regulating units when the basepoint ramp is in the direction that increases |AR| and |AR| is greater than a user adjustable limit.

UDG While AGC is SUSPENDED or TRIPPED:

When the AGC Control State is SUSPENDED, UDGs shall be determined as defined above for all units when AGC is ACTIVE except the UDG for all units with a unit control mode of REGULATE shall be determined as follows:

$$UDG_i = UDG_{i-1} + \Delta RBP_i.$$

The previous value of Unit Desired Generation UDG_{i-1} will include the last good value of the regulation component of UDG and there should be no "bump" in UDGI when AGC is SUSPENDED.

When the AGC Control State is TRIPPED, UDGs shall be determined as defined above for all units when AGC is ACTIVE except units with a unit control mode of REGULATE. The regulation component of UDG will be gradually removed from UDG of REGULATE units so that their UDGs will return to follow their ramped basepoint values within several minutes as follows:

$$UDG_i = UDG_{i-1} + \Delta RBP_i - K*ERRR_i*SIGN(UDG_{i-1} - RBP_i)$$

until $(UDG_{i-1} - RBP_i)$ changes sign, whereupon

$$UDG_i = UDG_{i-1} + \Delta RBP_i.$$

where K is a user adjustable constant between 0 and 1.0 that controls how quickly the regulation component of UDG is removed, and where UDGi is rate limited to a maximum change rate of RRR while the regulation component is being removed.

In a similar fashion, an individual regulating unit whose unit control mode is changed from REGULATE to MANUAL or BASE shall utilize the above calculation to remove the regulation component from its UDG whenever AGC is ACTIVE or SUSPENDED.

UDG While AGC Is OFF:

When the AGC Control State is OFF, UDGs shall be not be calculated or telemetered to any unit. The advisory 5-minute ~~SCD~~RTD basepoint calculated by ~~SCD~~RTD will still be sent to all units by ~~SCD~~RTD.

UDG with Reserve / Max Gen Pickup Activated:

When the either the Reserve Pickup or Max Gen Pickup mode in ~~SCD~~RTD-CAM is activated by the dispatcher, ~~SCD~~RTD-CAM executes immediately under relaxed limits and constraints including faster unit response rates (EMERGENCY vs. NORMAL) and higher upper limits (Upper Operating Limit less regulation margin vs. Upper Economic Limit). ~~SCD~~RTD-CAM sets the System Reserve Pickup flag and sets individual unit Reserve Pickup flags for all units selected for Reserve / Max Gen Pickup.

In Reserve / Max Gen Pickup mode, ~~SCD~~RTD-CAM calculates 10-minute basepoints for all units. At the end of the 10-minute period, the SPD cancels Reserve / Max Gen Pickup and ~~SCD~~RTD is restarted for normal execution.

When Reserve Pickup mode is activated, AGC shall calculate basepoint ramps as follows:

1) Reserve Pickup Unit – ramp unit to its ~~SCD~~RTD-CAM basepoint at its Emergency
Response Rate
2) Non-Reserve Pickup Unit – ramp unit to its ~~SCD~~RTD-CAM basepoint at its Normal Response Rate

When Max Gen Pickup mode is activated, AGC shall calculate basepoint ramps as follows:

1) Reserve Unit – ramp unit to its ~~SCD~~RTD-CAM basepoint at its Emergency Response Rate
2) Non-Reserve Unit - ramp unit to its ~~SCD~~RTD-CAM basepoint at its Emergency Response Rate

Reserve / Max Gen Pickup is canceled when any of the following conditions occur:

(a) 10-minutes time elapses
(b) Reserve or Max Gen Pickup is cancelled by dispatcher
(c) The value of AR enters the AR deadband
(d) AGC goes to OFF control state.

The Unit Reserve Pickup flag is also transmitted to each Reserve Pickup unit and the System Reserve Pickup flag to all units to alert them to the Reserve Pickup condition.

Regulation will continue as usual for units providing regulation only (REGULATE mode without Reserve / Max Gen Pickup flags set). The large AR should cause regulating-only units to raise at their Regulation Response Rates. Units providing both regulation and reserve will raise to the new ~~SCD~~RTD-CAM basepoints at their Emergency Regulation Response rates, assuming ERR > RRR.

At the end of 10 minutes or if Reserve / Max Gen Pickup is canceled by the dispatcher or AR returns within its deadband, both ~~SCD~~RTD and AGC shall execute again in their normal modes. During the period between the cancellation of the Pickup or the end of 10 minutes and the calculation of new 5-minute basepoints by ~~SCD~~RTD, AGC shall set unit basepoints equal to their actual generation values. AGC shall issue an alarm message to the dispatcher describing the reason for the cancellation or indicating the completion of Reserve Pickup.

Initial Step Change in UDG:

Due to the deadband inherent in unit control logic, a regulating unit that is not currently moving may not respond to a small change in UDG. In order to force a unit to respond sooner, AGC shall, under certain conditions, issue an initial step change to a regulating unit selected for control that is a user adjustable number of MWs greater than the unit's control deadband. This step change shall only be issued if all of the following conditions are present:

1) The unit is not moving
2) A small change in UDG is required (the absolute value of the difference between the unit's actual generation and the rate-limited UDG is less than a user adjustable factor times the unit deadband and $ERRR_i$ ¹0)
3) Little or no basepoint ramp (½BPR½< low limit)
4) The new UDG is in the direction to reduce AR (SIGN(AR) ¹SIGN(UDG_i - UDG_{i-1}))
5) The initial step change feature is specifically enabled for this unit.

After the step change, the unit's UDG shall not be modified for approximately "n" AGC control cycles, where n = (deadband)/(RRR/10) and RRR/10 = regulating response for one AGC control cycle.

Remove Windup in Previous Values of UDG:

When the value of AR returns within its deadband or changes sign, no further regulation in the direction to reduce AR is required since AR has already been satisfactorily controlled. To avoid control overshoot, the previous values of UDG for regulating units shall be adjusted to remove any windup in the regulation requirement to which a regulating unit had not yet responded.

Control windup shall be removed whenever AR returns to zero (within the AR deadband) or crosses zero (changes sign) and a regulating unit's UDG is either greater than or less than both its actual unit generation and unit ramped basepoint. Control windup shall be removed by setting the previous value of UDG to either unit actual generation or unit ramped basepoint, whichever is closer to UDG (see Figures 6-11, 6-12 & 6-13, Removal of Control Windup in UDG When AR Returns Near Zero, Cases 1, 2 & 3).

Fast–Response Units Return to Basepoint:

A unit that bids an RRR greater than a user adjustable response rate will be designated as a fast-response unit. To make better use of this category of unit, it will be operated close to its ~~SCD~~RTD basepoint whenever possible to allow it to respond quickly to a significant AR of either sign. Consequently, when AGC has controlled a fast-response unit to its Upper or Lower Operating Limit and the magnitude of AR becomes (or is already) less than a user adjustable limit, AGC shall control the unit back to its ramped ~~SCD~~RTD basepoint at a user adjustable rate. While it is being controlled to its basepoint, the unit shall not be available for regulation. When it is within its control deadband of its basepoint, it will again become available for regulation. If AR either becomes large or changes sign while a fast-response unit is being controlled back to its basepoint, the return to basepoint shall be cancelled and the unit shall become immediately available for regulation.

UDG Initialization:

Whenever the AGC Control State changes to ACTIVE or TRIPPED from OFF or TEST, AGC shall request an immediate execution of ~~SCD~~RTD. After ~~SCD~~RTD has generated new unit basepoints, AGC shall, for each unit, initialize the values of its UDG and the value of its old (previous) unit basepoint to the value of its actual generation.

Forbidden Operating Regions:

Normally, unit limits established for the generators will constrain unit operations under AGC control to regions that do not involve areas of rough unit operation. Nevertheless, each unit may have a forbidden region established by user adjustable high and low forbidden region limits. When the UDG for a unit falls less than halfway through the forbidden operating region, AGC shall move the unit only as far as the boundary of the forbidden operating region and move the unit no further. When the UDG for a unit falls more than halfway through or beyond a forbidden operating region, AGC shall notify the dispatcher. Upon dispatcher approval (per incident), AGC shall control the unit completely through the forbidden operating region at its fastest response rate (Emergency, Regulation or Normal). At the dispatcher's option for each unit, notification shall be suspended and AGC shall automatically permit crossing the forbidden zone, but no more frequently than a dispatcher entered delay period.

Governor Action:

Governor action forces unit generation to change in response to frequency deviations from 60 Hz. However, the control system at an individual generating unit may or may not automatically compensate its received UDG value for governor action.

For a unit controller that automatically biases its primary unit control action for governor action, AGC will continue to send UDG without change when an actual or scheduled frequency change occurs. For a unit without a governor or whose unit controller does automatically adjust UDG for governor action, AGC shall bias UDG so as to send the unit its desired generation inclusive of anticipated governor action. A user adjustable Governor Action Bias flag for each unit, whether regulating or not, shall indicate whether or not governor action bias should be added.

For a unit with the Governor Action Bias flag set, UDG shall be offset by the anticipated amount of governor action based on the actual frequency according to the following formula:

$UDG_g = UDG + \beta_g * (F_{Af} – 60)]$
where:

- UDG_g = UDG with governor action bias
- UDG = Unit Desired Generation calculated as defined previously
- β_g = Unit governor frequency bias (negative value)
- F_{Af} = Actual Frequency (filtered frequency from 1- second samples described in Section 6.3.1).

Each UDGg value shall be restricted to be within its associated UOL and LOL.

The values of UDG_g shall be telemetered to the appropriate ~~Transmission Provider~~Transmission Owner for retransmission to the units in its local area. AGC shall save the value of UDG_g, along with the governor action bias flag, for the Performance Tracking System. Actual frequency used for this calculation shall be filtered to reduce the sensitivity to high-periodicity variations in system frequency.

Monitoring Conditions To Request Immediate ~~SCD~~RTD Execution

AGC shall request an immediate execution of the ~~SCD~~RTD function whenever it detects conditions
that may result in poor response to the NERC CPS1, CPS2 or DCS criteria. These conditions include the following:

- Excessive AR
- Change of AGC control state from OFF/TEST to ACTIVE or TRIPPED
- Insufficient Raise and/or Lower Regulating Margins
- Insufficient Total System Regulation Response Rate.

~~The SCDRTD function cannot run more often than every 2.5 minutes. Every 6 seconds, AGC shall check the time of the most recent SCDRTD execution to determine whether at least 2.5 minutes have elapsed since the previous SCDRTD execution before another SCDRTD run is requested.~~

Available Regulation Margins:

AGC shall calculate the Available Raise and the Lower Regulation Margins every AGC cycle to determine whether either value falls below corresponding user adjustable limits for longer than a user adjustable period. The values of the Regulation Margins be the sum, for all units in REGULATE mode, of the absolute values of the difference between a unit’s actual generation and its corresponding Upper or Lower Operating Limit. When a regulating unit is limited by security constraints from moving in one or both directions, the unit shall not be included in the calculation of the corresponding Regulation Margin.

If either Regulating Margin falls below separate user adjustable thresholds for longer than a user adjustable interval, AGC shall issue an alarm message to the dispatcher and request an immediate run of ~~SCD~~RTD. The alarm message shall be repeated periodically if necessary. ~~SCD~~RTD, as part of its normal logic, will redispatch all generating units to reestablish the proper regulating margin if possible.

Total Available Regulation Response Rate:

AGC shall also compare the Total Available Regulation Response Rate (TARRR) in the direction to reduce AR (see Section 6.5.6) with the Required Regulation Response Rate (see Section 6.5.7). If TARRR falls below RRRR for more than a user adjustable number of control cycles, AGC shall issue an alarm message to the dispatcher and issue an immediate run request to ~~SCD~~RTD. This alarm message shall be repeated periodically if necessary.

Unit Response Testing

AGC shall be able to test the response characteristics of generating units to control signals of various magnitudes in both directions over different unit operating regions. AGC shall monitor the unit performance during the test and compile statistics, such as average response rate in raise and lower directions and overshoot. Two tests shall be able to run simultaneously (e.g., move two units in opposite directions to minimize the impact on AR).

~~Attachment D –~~
~~Regulation Performance Penalty~~

Attachment ~~D~~ C –
Regulation Performance Adjustment

Adjustment

Regulating units assist in maintaining both the scheduled interchange of energy with neighboring control areas and the scheduled frequency. The Automatic Generation Control (AGC) function monitors and controls net interchange and system frequency. The control of these quantities involves frequent signals to the suppliers of regulating service to adjust their output. Nominally, the AGC function requires an adjustment in the output of regulation service providers every six seconds. The effective control of interchange and frequency relies on the responsiveness of regulation service providers. That is, providers must react quickly and accurately to the control signals that would increase or decrease in output. The performance of regulation service providers is monitored and a payment factor is calculated for each provider. Good performers are paid for their regulation service at 100% of the market clearing price for regulation. Poor performers are paid only a portion of the market clearing price of regulation. That portion depends on the payment factor calculated for the provider – the worse (less responsive) the provider, the smaller the portion.

Symbol	Description
BP^{+}_{AGC30}	The largest of the six-second base points determined by AGC for a regulating unit over the past 30 seconds
BP^{-}_{AGC30}	The smallest of the six-second base points determined by AGC for a regulating unit over the past 30 seconds
$DAMCPreg_i$	Day-ahead clearing price of regulation service for the hour containing RTD interval "i"
$DARcap_i$	Amount of day-ahead regulation service scheduled from a supplier of regulation service for the hour containing RTD interval "i"
i	Index of an RTD interval.
K^{i}_{PI}	The regulation payment factor for RTD interval "i"
NCE_i	The negative control error of a regulating unit in RTD interval "i"
OG	Measured over-generation
PCE_i	The positive control error of a regulating unit in RTD interval "i"
PI_i	The regulation performance index in RTD interval "i"
PSF	The payment scaling factor
$RegPeriod_i$	Number of seconds during RTD interval "i" that the generating unit is supplying regulation service.
RR	Regulation ramp rate (MW/min) for a regulating unit
$Rsettlement_i$	Real-time portion of the settlement to a provider of regulation service for RTD interval "i"
$RTMCPreg_i$	Real-time clearing price of regulation service in RTD interval "i"
$RTRcap_i$	Amount of ~~real-time~~Real-Time regulation service scheduled in RTD interval "i" from a supplier of regulation service
s_i	Number of seconds in RTD interval "i"
UG	Measured under-generation
URM_i	The unit regulation margin in RTD interval "i"

Control Error

Both a positive and a negative control error are accumulated for each provider of regulation service in each RTD interval. The positive control error (PCE) is a measure of the provider's over-generation; the negative control error (NCE) is a measure of the provider's under-generation. Each 30 seconds the measured output of the regulation provider is compared to the largest and smallest of six-second base points generated during the previous 30 seconds. The provider is over-generating if measured output is greater than the largest of the six-second base points of the past 30 seconds. The provider is under-generating if measured output is less than the smallest of the six-second base points of the past 30 seconds. That is, every 30 seconds:

$$OG = \left(MW_{meas} - BP^{+}_{AGC30}\right),\ \textit{but not less than zero}$$

$$UG = \left(BP^{-}_{AGC30} - MW_{meas}\right),\ \textit{but not less than zero}$$

Over- and under-generation is accumulated for each 30-second period in the RTD interval. That is:

$$PCE_i = \sum_{\substack{30-\text{second periods}\\ \text{in the RTD interval}}} OG$$

$$NCE_i = \sum_{\substack{30-\text{second periods}\\ \text{in the RTD interval}}} UG$$

Unit Regulation Margin

The unit regulation margin is the amount that the regulation provider's output could change during an RTD interval. The unit regulation margin is calculated as:

$$URM_i = RR \times \left[\frac{s_i}{60}\right]$$

Regulation Performance Index

The regulation performance index tracks how well a regulation supplier responds to the control signals that are issued every six seconds. A regulation performance index is calculated for every RTD interval.

$$PI_i = URM_i - \left[\frac{PCE_i + NCE_i}{URM_i + 0.10}\right] \times \left[\frac{RegPeriod_i}{s_i}\right]$$

Regulation Payment Factor

A payment factor is calculated for each supplier of regulation service. The payment factor is used in the calculation of payments to the supplier. The payment factor is calculated as follows:

$$K_{PI}^{i} = \left[\frac{PI_i - PSF}{1 - PSF} \right]$$

Where:

PI is the Generator's performance index; and

PSF is the payment scaling factor, established pursuant to NYISO Procedures.

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

Settlement for Regulation Service

The settlement of a regulation service provider for regulation service includes portions for day-ahead commitments to provide regulation service (if any) and balancing adjustments to account for deviations between day-ahead and ~~real-time~~Real-Time awards. The regulation payment factor is applied to the ~~real-time~~Real-Time portion of the settlement as shown below for an RTD interval. Total settlement for the day is simply the sum of the interval settlements for all intervals in the day.

$$Rsettlement_i = (DARcap_i \times DAMCPreg_i) + [(RTRcap_i \times K_{PI}^{i}) - DARcap_i] \times RTMCPreg_i$$

~~Regulating Units~~

~~A 30 second bandwidth for regulation providers will be established and bounded by the highest and the lowest of the last five actual AGC signals and the last five modified AGC signals sent to that unit (assuming a nominal six-second AGC cycle), where the modified signal is computed by adjusting the actual AGC signal sent to a regulation provider as necessary in order to ensure that the regulation provider could follow the modified signal without being required to exceed its regulation ramp rate. Generators whose output is within this bandwidth will not incur regulation penalties. Generators whose output is outside this bandwidth will incur penalties for the amount by which they are outside their bandwidth.~~

~~Transmission Provider~~

~~A similar performance calculation is applied to all the regulating units as a single block. Financial penalties for poor performance will be assessed on a Transmission Provider basis.~~

~~Off-Dispatch & On-Dispatch/Non-Regulating Units~~

~~Figure D-1 shows how financial penalties are assessed to Off-Dispatch and On-Dispatch/Non-Regulating units for causing other units to regulate.~~

~~*Calculation of Average Absolute Unit Control Error (AAUCE)*~~

~~The average absolute unit control error is derived from a unit's deviation of the actual generation of the unit from the 30-second minimum and maximum of the predicted desired generation of the unit. One complication to this concept is that during periods where the real-time~~Real-Time ~~ACE is greater than the regulation requirement, the unit desired generation (UDG) will exceed the regulation ramp rate. The AAUCE for each regulating generator measures the amount by which its actual output falls outside this 30-second bandwidth. This section describes how the AAUCE for regulating generators is calculated, and provides an example illustrating that calculation.~~

~~Define A_{it} as the AGC signal sent to regulating generator *i* at time *t*, R_i as the number of MW/minute of regulation provided by regulating generator *i*, and M_{it} as the modified AGC signal for regulating generator *i* at time *t* (with the modification correcting the AGC signal to ensure that it does not call for a unit to move faster than the number of MW/minute of regulation it is providing). If AGC signals are sent out every six seconds, regulating generator *i* can be expected to move R_i/10 MW. Then, in most circumstances,~~

$$M_{i,t+1} = \begin{cases} M_{it} + R_i/10, & \text{if } A_{it} > M_{it} + R_i/10, \\ A_{it}, & \text{if } M_{it} - R_i/10 \le A_{it} \le M_{it} + R_i/10, \\ M_{it} - R_i/10, & \text{if } A_{it} < M_{it} - R_i/10. \end{cases}$$

~~This equation means that the modified AGC signal will move up if the previous period's actual AGC signal is above the previous period's modified AGC signal, and that it will move down if the previous period's actual AGC signal is below the previous period's modified AGC signal, but the amount by which the modified AGC signal can move, relative to the previous period's modified AGC signal, can be no greater than R_i/10.~~

~~There are two situations in which the above equation would not apply. In each of these situations, the actual AGC signal's relationship to the modified AGC signal has reversed direction (i.e., the actual AGC signal was above the modified AGC signal in one time period and was below it in the next time period or vice versa) and the actual generation level is closer to the new AGC signal than is the modified AGC signal. In such cases, modified AGC signals in future time periods should reflect the degree to which the generator can move toward the AGC signal starting from its actual generation level, rather than starting from its previous modified AGC signal. We can put this into equation form by letting G_{it} represent the amount of energy actually generated by regulating generator *i* at time *t*:~~

~~If~~

$$A_{i,t-1} > M_{i,t-1} \text{ and } 2A_{it} - M_{it} < G_{it} < M_{it}, \text{ then}$$

$$M_{i,t+1} = \begin{cases} G_{it} - R_i/10, & \text{if } A_{it} < G_{it} - R_i/10, \\ A_{it} & \text{otherwise.} \end{cases}$$

~~And if~~

$$A_{i,t-1} < M_{i,t-1} \text{ and } 2A_{it} - M_{it} > G_{it} > M_{it}, \text{ then}$$

$$M_{i,t+1} = \begin{cases} G_{it} + R_i/10, & \text{if } A_{it} > G_{it} + R_i/10, \\ A_{it} & \text{otherwise.} \end{cases}$$

~~Then, given this definition of the modified AGC signal, a regulating unit should not be penalized if either (1) its output is in between the maximum or the minimum of the AGC signals sent to it in the last 30 seconds, or (2) it has moved at its regulation ramp rate (at least). In other words, if we define~~ E_{it} ~~as the control error for regulating generator *i* for the AGC scan occurring at time *t*, then~~

$$E_{it} = \begin{cases} 0, & \text{if } L_{it} \le G_{it} \le U_{it}, \\ L_{it} - G_{it}, & \text{if } G_{it} < L_{it} \\ G_{it} - U_{it}, & \text{if } G_{it} > U_{it}, \end{cases}$$

~~Where~~ U_{it}~~, the upper bound of the envelope within which regulating generator *i* can operate without penalty, is:~~

$$U_{it} = \max(M_{it}, M_{i,t-1}, M_{i,t-2}, M_{i,t-3}, M_{i,t-4}, A_{i,t-1}, A_{i,t-2}, A_{i,t-3}, A_{i,t-4}, A_{i,t-5})$$

~~and~~ L_{it}~~, the lower bound of that envelope, is:~~

$$L_{it} = \min(M_{it}, M_{i,t-1}, M_{i,t-2}, M_{i,t-3}, M_{i,t-4}, A_{i,t-1}, A_{i,t-2}, A_{i,t-3}, A_{i,t-4}, A_{i,t-5})$$

~~The AAUCE over an RTD interval for regulating generator *i* would simply be the average of the control errors~~ E_{it} ~~occurring within that RTD interval.~~

~~Example~~

~~The table on the next page illustrates an example in which a unit is scheduled to provide 10 MW/minute of regulation. Initially, the AGC signal sent to that unit (~~A_{it}~~) also increases by 10 MW/minute (i.e., by 1 MW every six seconds), but at :36, the AGC signal sent to this unit jumps by 5 MW. After that jump, it continues to increase by 1 MW every six seconds until 1:24. After 1:24, the AGC signal sent to this unit stays constant at 33 MW.~~

~~Initially, this unit's actual output (~~G_{it}~~) is 5 MW below the AGC signal sent to that unit. Since 5 MW is equal to the amount that unit has been asked to move in the last 30 seconds (because the AGC signal is initially increasing at 1 MW every six seconds, and (1 MW / 6 sec.) × 30 sec. = 5 MW), this means that this unit's actual output is trailing the AGC signal sent to that unit by 30 seconds. A 30-second lag in response to the AGC signal will not cause a unit to incur a regulation penalty. Therefore, this unit should have a zero control error at times :30 and :36. (Control errors for times :00 through :24 have~~

~~not been included in the table because the table does not contain complete histories of all AGC signals sent within the 30 seconds preceding each of those times.)~~

~~And, in fact, the equations described above yield a control error (E_{it}) for this unit of zero at times :30 and :36. The table illustrates how the range within which this unit's control error is zero is calculated. At time = :30, for example, L_{it} (the lower bound of this acceptable range) is 15 MW, which was the lowest AGC signal sent within the preceding 30 seconds, while U_{it} (the upper bound of this acceptable range) is 19 MW—the highest AGC signal sent within the preceding 30 seconds. G_{it} falls within the envelope defined by L_{it} and U_{it}, causing the control error to be zero.~~

Time	A_{it}	M_{it}	U_{it}	L_{it}	G_{it}	E_{it}
:00	15	14			10	
:06	16	15			11	
:12	17	16			12	
:18	18	17			13	
:24	19	18			14	
:30	20	19	19	15	15	0
:36	25	20	20	16	16	0
:42	26	21	25	17	17	0
:48	27	22	26	18	18	0
:54	28	23	27	19	19	0
1:00	29	24	28	20	20	0
1:06	30	25	29	21	21	0
1:12	31	26	30	22	22	0
~~1:18~~	~~32~~	~~27~~	~~31~~	~~23~~	~~23~~	~~0~~
1:24	33	28	32	24	24	0
1:30	33	29	33	25	25	0
1:36	33	30	33	26	26	0
1:42	33	31	33	27	27	0
1:48	33	32	33	28	28	0
1:54	33	33	33	29	28	1
2:00	33	33	33	30	28	2
2:06	33	33	33	31	28	3
2:12	33	33	33	32	28	4
2:18	33	33	33	33	28	5
2:24	33	33	33	33	28	5
2:30	33	33	33	33	28	5

$R_i/10$ = 1

~~While A_{it} jumps upward at :36, M_{it}, which modifies the AGC signal so that it will not be necessary for a unit to exceed its regulation ramp rate in order to follow the AGC signal, continues to increase at 1 MW every six seconds—since that is the regulation ramp rate for this unit. As a result, the gap between L_{it} and U_{it} widens. At time = 1:12, for example, L_{it} is now equal to the lowest modified AGC signal sent within the preceding 30 seconds, which is 22 MW. While the lowest actual AGC signal sent in the last 30 seconds is the 26 MW signal sent at :42, requiring the unit to increase its output to at least 26 MW would have required it to exceed its 10 MW/minute regulation ramp rate. However, while the unit will not be penalized for failing to exceed that ramp rate, it also will not be penalized for doing so. As a result, U_{it} is set equal to 30 MW—the highest actual AGC signal sent in the last 30 seconds. Since G_{it} continues to fall within the envelope defined by L_{it} and U_{it}, the unit's control error continues to be zero.~~

~~The gap between A_{it} and M_{it} begins to close after the A_{it} signal flattens out at 1:24, and as a result the range between L_{it} and U_{it}, which defines zero control error, also begins to decrease. In the time periods immediately following 1:24, the unit continues to increase its output by 1 MW, as it catches up on the 5 MW jump in the AGC signal that occurred at :36, as well as catching up on the 30-second lag that existed before that jump in the AGC signal. As a result, it stays within this envelope, even though the envelope is narrowing, and the unit's control error remains zero. However, at 1:48, the unit's actual output also flattens. At this point, the unit's actual output is 28 MW, which is 5 MW below the AGC signal that is being sent out to the unit. Since the unit had been operating at the low end of the range defined by L_{it} and U_{it}, a positive control error immediately results from its failure to continue to increase its output at its regulation ramp rate until it reaches the 33 MW AGC signal. At time = 2:00, for example, the control error is 2 MW, since the lowest modified AGC signal issued within the last 30 seconds is 30 MW, 2 MW above the unit's actual output level at that time. Finally, at time = 2:30, the control error reaches 5 MW, since the generator's output is 5 MW below the 33 MW AGC signal sent by that unit, the unit has been sending a steady AGC signal over the last 30 seconds, and enough time has elapsed so that the unit could have reached an output level of 30 MW if it had continued to increase its output at its 10 MW/minute regulation ramp rate.~~

~~*Regulation Charge for Regulation Providers*~~

~~The NYISO does not impose performance penalty charges on Regulation and non-Regulation suppmliers; however, the NYISO reserves the right to impose/reinstate these charges, if the degradation of the Regulation supplier's performance threatens compliance with standards established by the North American Reliability Commission (NERC), the Northeast Power Coordinating Council (NPCC), and with the standards of Good Utility Practice for Control Performance, and if the degradation in performance compromises reliability.~~

~~Regulation suppliers will pay a penalty to the NYISO for poor regulation performance equal to the AAUCE for each RTD interval, multiplied by the real-timeReal-Time regulation price for that RTD interval, times the ratio of the RTD interval's length to 60 minutes. If there is no real-timeReal-Time market for regulation, then day-ahead prices will be used to determine these penalties for regulation providers.~~

~~***Non-Regulating Units***~~

~~A Supplier that is not providing Regulation Service and that persistently operates at a level below its schedule shall pay a persistent undergeneration~~under-generation ~~charge to the ISO, unless its operation is within a tolerance described below. Persistent undergeneration~~under-generation ~~charges per interval shall be calculated as follows:~~

~~Persistent undergeneration~~under-generation ~~charge = Energy Difference x MCPreg x Length of Interval/60 Minutes~~

~~Where:~~

~~Energy Difference in (MW) is determined by subtracting the actual Energy provided by the Supplier from its RTD Base Point Signal for the dispatch interval. The Energy Difference shall be set at zero for any Energy Difference that is otherwise negative or that falls within a tolerance, set pursuant to NYISO~~

~~Procedures, and which shall contain a steady-state and a dynamic component. The steady-state component shall initially be 3% of the Supplier's Normal Upper Operating Limit or Emergency Upper Operating Limit, as applicable, and the dynamic component shall be a time constant that shall initially be set at fifteen minutes; and~~

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

~~Generators that are not providing regulation may also be subject to regulation penalties if they do not follow their RTD basepoints and thereby increase the NYCA's regulation burden. However, these units will be permitted a tolerance level. If the deviation between actual output and ramped RTD basepoints does not exceed this tolerance level, then the unit will not be penalized. If this deviation exceeds the tolerance level, the unit will be penalized for the amount by which the deviation exceeds the tolerance level.~~

~~*Performance Index*~~

~~The deviation tolerance allowed non-regulating units is based on the degree to which regulating units follow their AGC signals.~~

~~A performance index for each regulating generator (PI_{Reg}) is calculated based on a normalization of a unit's control error with respect to its regulation margin. The value being normalized is the average absolute unit control error (AAUCE). A grace value will be awarded all regulating units to compensate for the inherent control delay and imperfect response of any real unit. The grace value will be set by the NYISO and will initially be set to 10%. The PI_{Reg} will be truncated to a maximum value of 1.0.~~

~~The performance index for each regulating unit is calculated as follows:~~

~~PI_{Reg} = [(Reg Margin - AAUCE)/(Reg Margin) + 0.10]~~

~~Where:~~

~~Reg Margin = MW of regulation the generator is scheduled to provide. This value can not exceed the greater of five times its RRR.~~

~~AAUCE = Average absolute unit control error~~

~~*Control Area Performance Index*~~

~~Once each individual PI_{Reg}s has been calculated, the performance index for the Control Area is calculated by averaging the individual PI_{Reg}s.~~

$$NYCAPI_{Reg} = \frac{\sum_{i=1}^{n} (PI_{Reg}(i) * RegMargin(i))}{\sum_{i=1}^{n} RegMargin(i)}$$

~~Where:~~

~~PIReg(i) = The PIReg of unit i~~

~~n = total number of regulating units in the NYCA~~

~~*Non-Regulating Unit Deviation Tolerance*~~

~~The deviation tolerance will be calculated as a fixed percentage of the generating units OpCap modified by the Control Area regulation performance index from the previous RTD interval. Deviation tolerance is calculated as follows:~~

$$DevTol_i = OpCap_i * Fixed\% * NYCAPI^2_{\mathrm{Re}\,g}$$

~~Where:~~

~~i = the unit number~~
~~Fixed% = initially set at 1%~~
~~$NYCAPI_{Reg}$ = New York Control Area regulation performance index averaged over the previous week.~~

~~An example would be a 1000MW generating unit has a deviation tolerance of 10MW for the current RTD interval if $NYCAPI_{Reg}$ from the previous week is 1.0 (perfect).~~

~~If $NYCAPI_{Reg}$ from the previous week is 0.9 for the above example then the deviation tolerance becomes 10MW * (0.9)2 or 8.1MW.~~

~~*Regulation Charge for Generators Not Supplying Regulation*~~

~~As Figure 4.4.2 shows, non-regulation suppliers will pay a regulation penalty to the NYISO if their deviation from their ramped RTD basepoint exceeds this tolerance level. This penalty will be equal to the amount by which the AAUCE for these non-regulating units over the course of an RTD interval exceeds the tolerance level, multiplied by the real-time~~Real-Time ~~price of regulation for that RTD interval, times the ratio of the RTD interval's length to 60 minutes.~~

~~If there is no real-time~~Real-Time ~~market for regulation, then day-ahead prices will be used to determine these penalties for regulation providers.~~

~~For SCE > 0:~~

~~If AAUCE >Ramp RTD + DevTol~~
~~Then Reg Penalty = (ActGen - Ramp RTD - DevTol) * MCP~~
~~Else Reg Penalty = 0~~

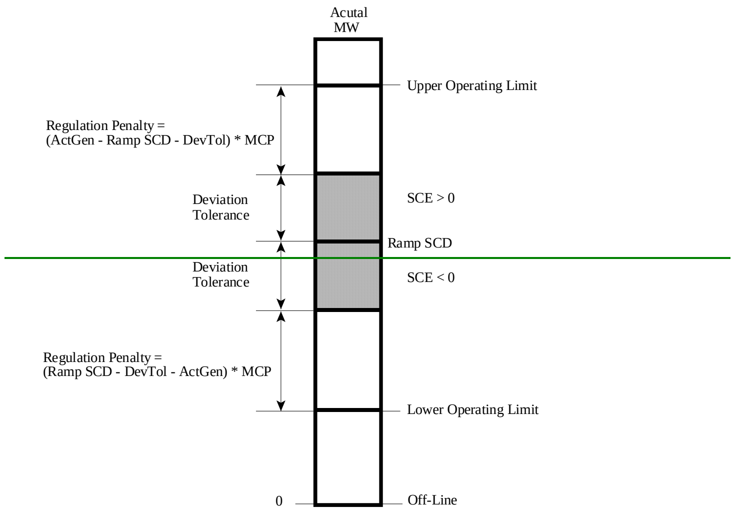
~~For SCE < 0~~

~~If AAUCE < Ramp RTD - DevTol~~
~~Then Reg Penalty = (Ramp RTD - ActGen - DevTol) * MCP~~
~~Else Reg Penalty = 0~~

~~Where:~~

~~SCE = Satellite Control Error~~
~~Ramp RTD = linearly interpolated value between RTD executions, in MW~~
~~ActGen = actual unit output, in MW~~
~~AAUCE = is as defined below~~
~~DevTol = Deviation Tolerance = OP Cap * Fixed Percent * PI2TP/100~~
~~Reg Penalty = Regulation Penalty, in $/MW~~
~~MCP = Market Clearing Price, in $/MW~~

~~Figure 4.4.2 shows how financial penalties are assessed to Off-Dispatch and On-Dispatch/Non-Regulating units for causing other units to regulate.~~



~~**Figure D-1: Penalties for Non-Regulation Providers**~~

~~The AAUCE for each non-regulating unit within each RTD interval will be calculated by averaging the following over that RTD interval:~~

$$\cancel{\left|RampSCD_{it} - G_{it}\right|}$$

~~Where:~~

~~RampRTD$_{it}$ = ramped RTD basepoint for generator *i* at time *t*: and~~

~~G$_{it}$ = generation by generation *i* at time *t*.~~

~~RampRTD will be calculated by linearly interpolating the RTD basepoint from the preceding RTD interval and the RTD basepoint for the current RTD interval over the first five minutes of the current RTD interval. If the current RTD interval exceeds five minutes in length, the ramped RTD basepoint for all times five minutes or more after the beginning of the RTD interval will be equal to the RTD basepoint for that interval.~~

~~Also, in cases when the NYISO has announced a reserve pickup, the term *RampRTD$_{it}$-G$_{it}$* will be set to zero for all times t at which G$_{it}$ >RampRTD$_{it}$, if generator i is in an area affected by the reserve pickup.~~

~~Examples illustrating these procedures follow:~~

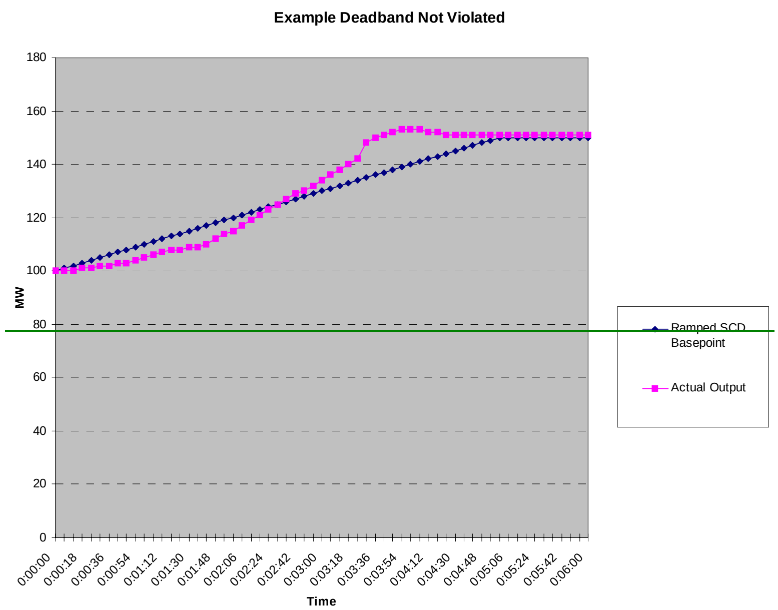
~~*Examples*~~

~~*Example 1*~~

~~An On-Dispatch Unit Does Not Violate the Deviation Tolerance.~~

~~The unit is a 600 MW (OpCap) unit that had a last basepoint and actual output of 100 MW. The new basepoint received at the top of the hour is 150 MW. Note that if the NYISO regulation performance index is perfect at 1.0 then the deviation tolerance would be 6 MW. The chart below gives a visual indication of how a generating unit might be expected to respond. Although the information on unit control error is not explicitly shown, the average value was hand calculated at approximately 4.98 MW, which is less than the deviation tolerance. Also, note that in this example the RTD interval was extended to 6 minutes. This demonstrates that after the first 5 minutes the ramped basepoint expected response of the unit remains flat at 150 MW until the next RTD~~

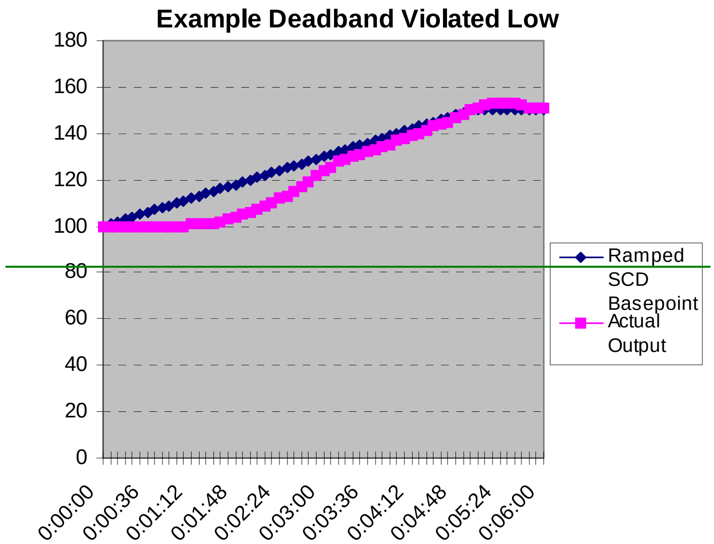
~~execution. In this case no penalties would be incurred. Additionally, note that the average actual response is slightly more than the average ramped basepoint expected response so the unit does get paid for energy based on the average ramped basepoint expected response.~~



~~*Example 2*~~

~~An On-Dispatch Unit that violates the Deviation Tolerance due to Under-Generation.~~

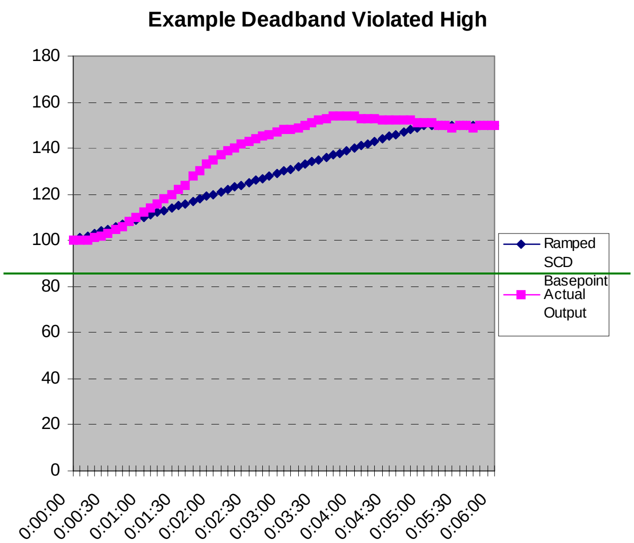
~~The unit is a 600 MW (OpCap) unit that had a last basepoint and actual output of 100 MW. The new basepoint received at the top of the hour is 150 MW. Note that if the NYISO regulation performance index is perfect at 1.0 then the deviation tolerance would be 6 MW. The chart below gives a visual indication of how a generating unit might be expected to respond when under-generating. Although the information on unit control error is not explicitly shown, the average value was hand calculated at approximately 6.38 MW, which is greater than the deviation tolerance. Also, note that in this example the RTD interval was extended to 6 minutes. This demonstrates that after the first 5 minutes the ramped basepoint expected response of the unit remains flat at 150 MW until the next RTD execution. In this case the unit would get paid for its average actual energy output, because its average actual output is less than the average ramped RTD basepoint sent to that unit. The unit would be charged the real-time~~Real-Time~~ price of regulation multiplied by 0.38 MW, since this is the amount by which the unit's average absolute unit control error exceeded the deviation tolerance.~~



~~*Example 3*~~

~~An On-Dispatch Unit Violates the Deviation Tolerance due to Over-Generation.~~

~~The unit is a 600 MW (OpCap) unit that had a last basepoint and actual output of 100 MW. The new basepoint received at the top of the hour is 150 MW. Note that if the NYISO regulation performance index is perfect at 1.0 then the deviation tolerance would be 6 MW. The chart below gives a visual indication of how a generating unit might be expected to respond when over-generating. Although the information on unit control error is not explicitly shown, the average value was hand calculated at approximately 8.1 MW, which is greater than the deviation tolerance. Also, note that in this example the RTD interval was extended to 6 minutes. This demonstrates that after the first 5 minutes the expected response of the unit remains flat at 150 MW until the next RTD execution. In this case the unit would be paid for its expected energy output, because its average actual output is greater than the average ramped RTD basepoint sent to that unit. The unit would be charged the real-time~~Real-Time ~~price of regulation multiplied by 2.1 MW, since this is the amount by which the unit's control error exceeded the deviation tolerance.~~


Example Deadband Violated High
180
160
140
120
100
80
60
40
20
0
0:00:00
0:00:30
0:01:00
0:01:30
0:02:00
0:02:30
0:03:00
0:03:30
0:04:00
0:04:30
0:05:00
0:05:30
0:06:00
Ramped SCD Basepoint
Actual Output

Attachment D —— Performance Standards

The link below will take you to the most current performance standard information on the North American Electric Reliability Council (NERC) website.

ftp://www.nerc.com/pub/sys/all_updl/oc/opman/PerformStdsRef.pdf
~~ftp://www.nerc.com/pub/sys/all_updl/oc/opman/policy1_BOTApproved_1002.doc~~

~~**Attachment F - Performance Penalties**~~

~~This Attachment sets forth the details of a policy to provide an interim deferral from billing for regulation penalties to those entities that are described in and comply with the terms of this Attachment.[1] It also describes how energy balancing will be applied to transactions described herein.[2] The NYISO will defer billing for regulation performance penalties according to the terms set forth in this Attachment. However, deferred amounts shall remain the obligation of the entity responsible for regulation performance penalties under the NYISO Market Administration and Control Area Services Tariff or the NYISO Open Access Transmission Tariff, but for this Attachment, unless FERC approves a permanent exemption and allows the NYISO to forgive deferred amounts retroactively.~~

~~Qualifications~~

~~These rules apply to all entities seeking an exemption from regulation penalties that sell or schedule energy in the NYCA from generators in the categories described below. The rules in this Attachment also apply to entities that are purchasing energy from Category 1, 2 or 3 generators, the transactions for which are identified as Class 1 transactions.~~

~~Category 1~~

~~All generators that are currently Qualifying Facilities (QF Generators) as defined in the Public Utilities Regulatory Policy Act (PURPA) of 1978 selling energy to, or purchasing energy within, the NYCA pursuant to an existing FERC-filed Power Purchase Agreement (PPA). Transactions under PURPA contracts are eligible for Class One treatment as described below. Class Two treatment is only available if the selling and purchasing entity are the same organization for NYISO billing purposes. QF Generators may submit properly noticed transactions pursuant to existing PPAs that were not filed at FERC, for the exemptions described herein, as Class One transactions.[3] Merchant contracts will be balanced pursuant to existing tariff provisions.~~

~~Category 2~~

~~Any generator that is an existing topping or extraction turbine generator, or replaces or re-powers such a facility and that produces electric energy as a result of supplying steam to the district steam system located in New York City (LBMP Load Zone J), provided that the total capacity of such generators does not exceed 365 MW. Transactions with Category 2 units are eligible for Class Two treatment as described below unless specifically identified and noticed to the NYISO for Class One treatment. Sales to the LBMP Market are Class Two transactions.~~

~~Category 3~~

[1] In Docket Nos. ER00-550-000 and ER00-556-000, FERC rejected a proposal by the NYISO and Member Systems to amend the ISO Services Tariff to create an exemption from regulation penalties substantially similar to the exemption described in this Technical Bulletin. In its Order dated January 12, 2000, FERC stated that it rejected the proposed exemption without prejudice to refiling the proposal in a separate docket including appropriate justification and cost support. Provided that parties adhere to the terms of this Technical Bulletin, the NYISO will refile its proposal with FERC and seek an exemption from regulation performance penalties according to the terms set forth in this Technical Bulletin.

[2] See NYISO Market Administration and Control Area Services Tariff §§4.18, and Attachment B; NYSO OATT Attachment J.

[3] The term “existing contracts” for the purpose of this paragraph are those contracts in existence as of November 18, 1999, the effective date of energy balancing provisions in the NYISO Market Administration and Control Area Services Tariff in Docket Nos. ER00-550-000, ER00-556-000.

~~Any generator that is a non-schedulable renewable resource (i) in commercial operation as of November 18,1999, or (ii) in the process of seeking any necessary permits to commence construction as of November 18, 1999 or (iii) among the first 50 MWs beyond those that qualify as of November 18, 1999, to either be included in the NYISO's Interconnection Queue or, if not required by NYISO procedures to be included on the ISO's queue, to have noticed its intention to interconnect to its local Transmission Owner, provided that such resources do not qualify in Category 1. For the purposes of this Attachment, a non-schedulable renewable resource includes wind generation and run-of-river hydro generation plants that are larger than 1 MW. Hydro units must petition the NYISO to be included in Category 3 and must provide adequate documentation to support the claim that the output from their facility is subject to river flows or other natural forces that preclude dependable and accurate scheduling of the facility's output. Transactions with Category 3 units are eligible for Class Two treatment as described below unless specifically identified and noticed to the NYISO for Class One treatment. Sales to the LBMP market are Class Two transactions.~~

~~Required Actions of Qualified Entities~~

~~All generators seeking deferral hereunder must provide a letter signed by an authorized officer certifying to the NYISO that its facility qualifies in one of the three categories described above. Further, purchasing and scheduling entities seeking deferral must provide a letter signed by an authorized officer certifying to the NYISO that its business arrangements with the Category 1, 2 or 3 resource meet the criteria set forth in this Attachment.~~

~~Certification letters must include sufficient relevant information to support the claimed status. Certification letters for Category 1 resources must include:~~

~~The PPA's FERC identification number, or other relevant contractual information~~

~~The effective term of the PPA~~

~~The identity of the Purchaser as defined in the PPA~~

~~The identity of the party that is contractually responsible for submitting Day Ahead and Hour Ahead schedules to the NYISO~~

~~A statement that the facility is currently a Qualifying Facility under PURPA.~~

~~Certification letters for Category 2 & 3 generators must contain sufficient information to document qualifying characteristics outlined above.~~

~~In addition, the Purchasing or Scheduling Entity must provide identifying information for eligible transactions to the NYISO. This identifying information is the transaction's source, its sink, and its unique user reference in the NYISO's Market Information System.~~

~~Each generator or scheduling entity in Category 1 must identify the transactions in which they are engaged as either "Class One" or "Class Two," as appropriate for the purpose of determining treatment of energy imbalances. See description of Class One and Class Two transactions below. For Class One treatment, both the selling and purchasing entity must identify the transaction to the NYISO as a Class One transaction. A single identification can pertain to a series of scheduled transactions.~~

~~*In addition:*~~

- ~~Entities shall follow the bidding and scheduling requirements contained in the NYISO's Tariffs and procedures. In the event that there is a conflict between a previously published procedure, and an action listed here, the requirements of this Attachment will take precedence.~~

- ~~Generators must promptly notify the relevant Transmission Operator of any changes in operation (e.g. forced outages and derations) that will cause an expected or immediate change in output. Deviations due to normal operating conditions (temperature related) do not require notification.~~

- ~~Transmission Operators will promptly notify the NYISO of expected or immediate changes in operation (e.g. forced outages and derations) based upon either a direct communication from the relevant generator, or the Transmission Operator's observation of the generator's output.~~

- ~~Updates to the advisory schedule must be provided by the Scheduling entity as specified in Technical Bulletin # 25 "Updating Generator Limits Used in Real Time via Transmission Owners" and Bulletin # 44 "Generator Outage Notification."~~

- ~~Unless separately provided for in an agreement with the NYISO, scheduling entities may not submit an external proxy bus as a sink for a "Class One" transaction.~~

~~NYISO Implementation~~

~~A stacking order of transactions from a single qualified entity may also be provided to the NYISO. This stacking order will apply to any reductions or increases in output when multiple transactions -- including ineligible merchant transactions -- are assigned to the unit. The stacking order determines the allocation of reductions and increases among all transactions. If no stacking order is provided then multiple transactions will be reduced on a pro rata basis and increases in output will be assigned on a pro-rata basis.~~

~~The energy required to meet a Class One merchant contract will always be balanced at LBMP when the unit's output does not meet all of its obligations. If the output of a unit qualifying under Category One, is reduced to a point where it is not meeting its PURPA contracts, the PURPA transactions will be reduced in the manner described above.~~

~~For purposes of calculating Regulation Performance Penalties the NYISO will, for Class One and Class Two transactions, reset transaction obligations for each dispatch interval equal to the generator output -- after the fact -- such that no regulation performance penalty will apply.~~

~~*In addition:*~~

- ~~The NYISO will not require explanation to accept advisory schedule updates as described above.~~

- ~~The NYISO will monitor advisory schedules and generator output to assure that the Scheduling Entity is providing a reasonable advisory schedule and updates as necessary.~~

- ~~The NYISO will monitor scheduled transactions for the purpose of distinguishing eligible transactions from those that are ineligible for Class One or Class Two treatment. Generators scheduled to provide Regulation Service or Reserves are ineligible for the adjustments described herein.~~

~~Results~~

~~The above actions will result in the following:~~

- ~~For the purpose of calculating regulation performance penalties for qualifying transactions, the NYISO will set actual deliveries and advisory schedule deliveries equal in the Billing and Accounting System, so that qualified entities will not be billed on a monthly basis for regulation performance penalties.~~

- ~~Generators engaged in Class One transactions will not be subject to real-time~~Real-Time ~~energy imbalance penalties, as long as the DAM scheduling protocols described above are followed. Loads engaged in Class I transactions will be balanced in the Real-Time Market.~~

- ~~Class Two transactions will be balanced in accordance with the NYISO tariff, provided however, that qualified entities will be paid for energy generated beyond their real time obligations at Real-Time LBMP rates.~~

- ~~Category 1, 2 or 3 generators will be allowed to set the DAM LBMP and will not be allowed to set the Real-Time LBMP.~~

~~Both Class One and Class Two transactions for Category 1, 2 and 3 resources are currently subject to regulation penalties under the NYISO Tariffs. Until such time as FERC rules on an exception for these units, the NYISO will provide an interim deferral from monthly billing, in accordance with the rules in this Technical Bulletin. If such exception is not approved by FERC, the NYISO will implement whatever actions are required by FERC or otherwise consistent with the approved NYISO Tariffs.~~