NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Guideline

Primary Frequency Control

Preamble

It is in the public interest for the North American Electric Reliability Corporation (NERC) to develop guidelines that are useful for maintaining or enhancing the reliability of the Bulk Electric System (BES). The Technical Committees of NERC; the Operating Committee (OC), the Planning Committee (PC) and the Critical Infrastructure Protection Committee (CIPC) per their charters are authorized by the NERC Board of Trustees (Board) to develop Reliability (OC and PC) and Security Guidelines (CIPC). These guidelines establish a voluntary code of practice on a particular topic for consideration and use by BES users, owners, and operators. These guidelines are coordinated by the technical committees and include the collective experience, expertise and judgment of the industry. The objective of this reliability guideline is to distribute key best practices and information on specific issues critical to maintaining the highest levels of BES reliability. Reliability guidelines are not to be used to provide binding norms or create parameters by which compliance to standards is monitored or enforced. While the incorporation and use of guideline practices is strictly voluntary, the review, revision, and development of a program using these practices is highly encouraged to promote and achieve the highest levels of reliability for the BES.

Frequency Control

Much of the technical background on frequency response can be found in the 2012 Frequency Response Initiative Report (FRI). The FRI report provides a detailed explanation of many of the intricacies of frequency response and the reader is encouraged to review that document for a more thorough discussion of the subject.

To understand the role Primary Frequency Control plays in system reliability, it is important to understand different components of frequency response, and how individual components relate to each other. For the purpose of this guideline, the focus will be on Primary Frequency Control with Primary Frequency Response and Secondary Frequency Control also illustrated.

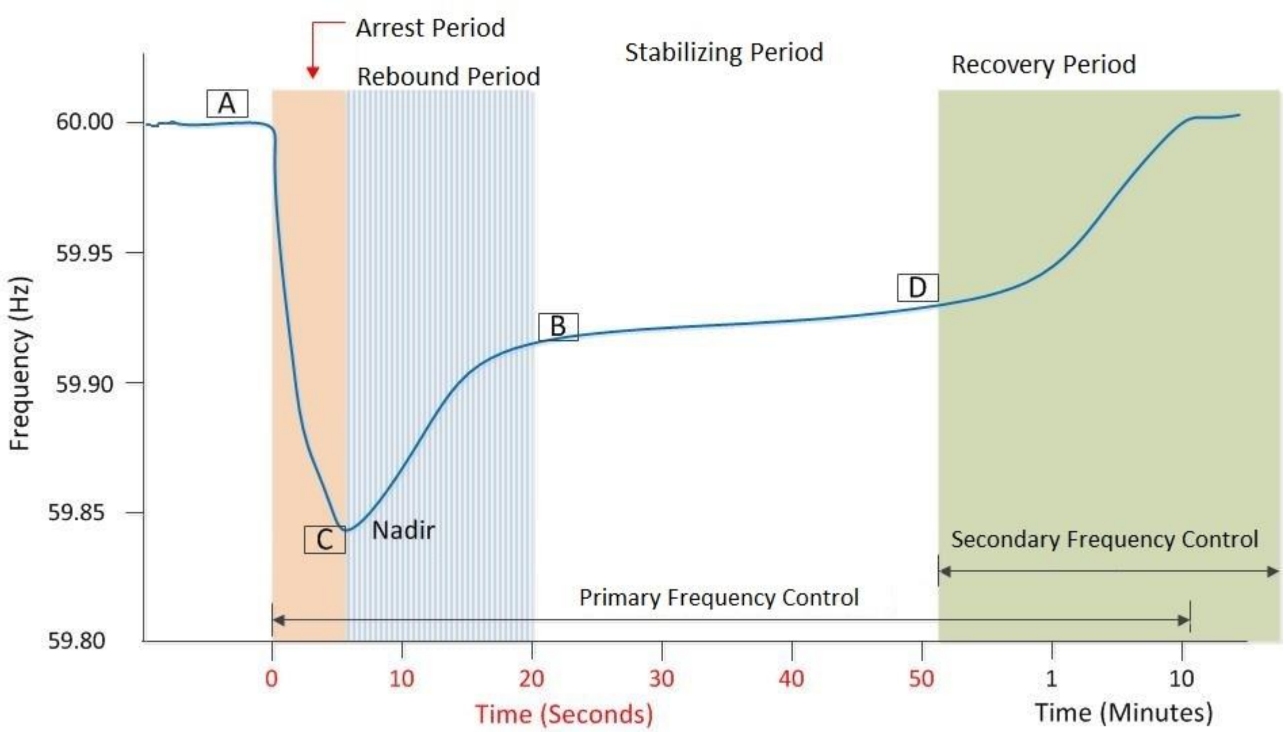
Definitions Used

- **Primary Frequency Response (PFR) (commonly referred to as Frequency Response)** – Actions from uncontrolled (natural) sources in response to changes in frequency: rotational inertia (H) response from resources and load response from frequency dependent loads (e.g. motors). In addition, it can come from Primary Frequency Control (as described below).
- **Primary Frequency Control** – A subset of Primary Frequency Response actions provided by prime mover governors in an interconnection to arrest and stabilize frequency in response to frequency deviations. Primary Frequency Control comes from local control systems.

- **Secondary Frequency Control** – Actions provided by an individual Balancing Authority to correct the resource-to-load imbalance that created the original frequency deviation that will restore both Scheduled Frequency and Primary Frequency Response. Secondary Frequency Control comes from either manual or automated dispatch from a centralized control system such as Automatic Generation Control (AGC).

Primary Frequency Control is essential for maintaining the reliability of the BES. For example, Planning Authorities' stability studies use models based on generator parameters, including governors' frequency control parameters, reported by Generator Owners. These same models are also used to evaluate Under Frequency Load Shedding (UFLS) needs and assess the frequency response of the system during restoration activities. Actual performance differing from that expected using reported values, whether within recommended deadband and droop settings or not, could detrimentally affect system reliability.

Point A is defined as the predisturbance frequency; Point C or Nadir is the maximum deviation due to loss of resource; Point B is defined as the stabilizing frequency and; Point D is the time the contingent Balancing Authority begins the recovery from the loss of resource.



Note: Some Secondary Frequency Control may begin earlier or later than illustrated. Also, some Primary Frequency Control may end earlier than illustrated due to governor deadband.

Purpose

This Reliability Guideline provides a strategy for Primary Frequency Control during frequency deviation events, as well as information to the industry recommending governor deadband and droop settings that will potentially enable resources to provide better frequency response to the BES. For the ERCOT Interconnection, governor deadband and droop settings are requirements set forth in NERC Regional Standard (BAL-001-TRE-1). Similarly, WECC has a Regional Criterion stating that if generating resources have governors, droop settings should be within a three to five percent range.

This guideline is intended to assist Balancing Authorities, Generator Operators, and Generator Owners in providing more effective frequency response during major grid events, and to address techniques of measuring frequency response at a resource level. It is offered as information to other Functional Model entities.

This Reliability Guideline outlines a coordinated operations strategy for resources to stabilize system frequency when frequency deviates due to a grid event. It is designed to keep frequency within allowable limits while maintaining acceptable frequency control. This Reliability Guideline is not applicable to resources that are connected to asynchronous loads or systems that are not normally a part of one of the Interconnections.

This Guideline does not create binding norms, does not establish mandatory Reliability Standards and does not create parameters by which compliance with Reliability Standards are monitored or enforced. In addition, this Reliability Guideline is not intended to take precedence over any Regional procedure.

Guideline Details

Primary Frequency Control is the first stage of overall frequency control and is the response of resources to arrest the locally measured or sensed changes in frequency. The controlled response of Primary Frequency Control is automatic, is not driven by any centralized system, and begins within cycles of the frequency change rather than minutes.

By having Primary Frequency Control, the impact of events on the BES can be minimized and better frequency control obtained. If frequency on the BES is not within the normal operating range, Primary Frequency Control should be sufficient to assist in arresting and stabilizing of abnormal frequency.

In order to provide Primary Frequency Control, it is recommended that all resources connected to an Interconnection be equipped with a working governor or equivalent frequency control device.

The primary focus of this Guideline is prime mover governors. Other forms of resources providing frequency response should have similar response characteristics described herein for governors.

Primary Frequency Coordination

In order to provide sustained primary frequency response, it is essential that the prime mover governor, plant controls and remote plant controls are coordinated. The lack of coordination between governor and load control systems will reduce primary frequency response, increase generator movement, and could increase grid instability.

Modern and legacy power plants are equipped with a wide variety of governor and plant control systems. In general, all prime movers will utilize some form of speed governor. Typically, this is a core part of the machines over speed protection as well as the foundation for the speed droop governor.

Modern systems generally incorporate a form of plant or unit load control. These Load Control Systems can be locally or remotely controlled and can be applied within the turbine control panel, the plant control panel or even remotely from a central dispatch center. In each of these control systems, the primary frequency control of the turbine governor must be taken into account to achieve sustained primary frequency response. Without coordination of the turbine governor's response to all speed changes, these additional control systems will react to the primary frequency response as a control error and quickly reverse the action of the governor. See Figure 1 below.

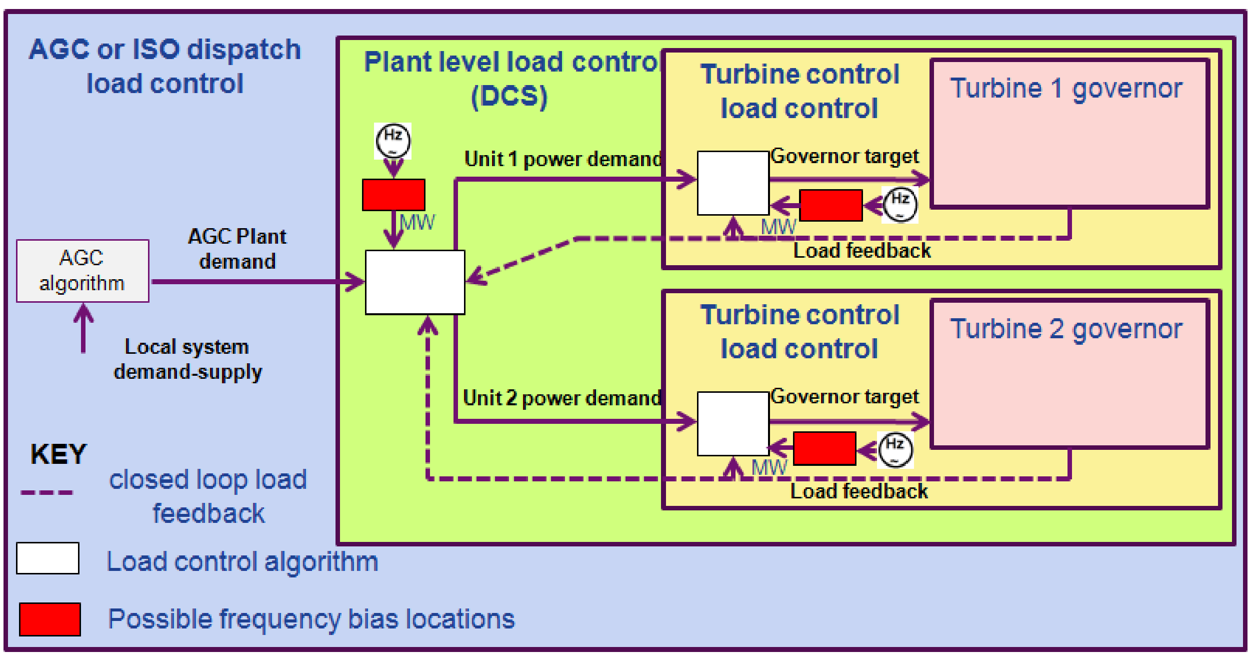


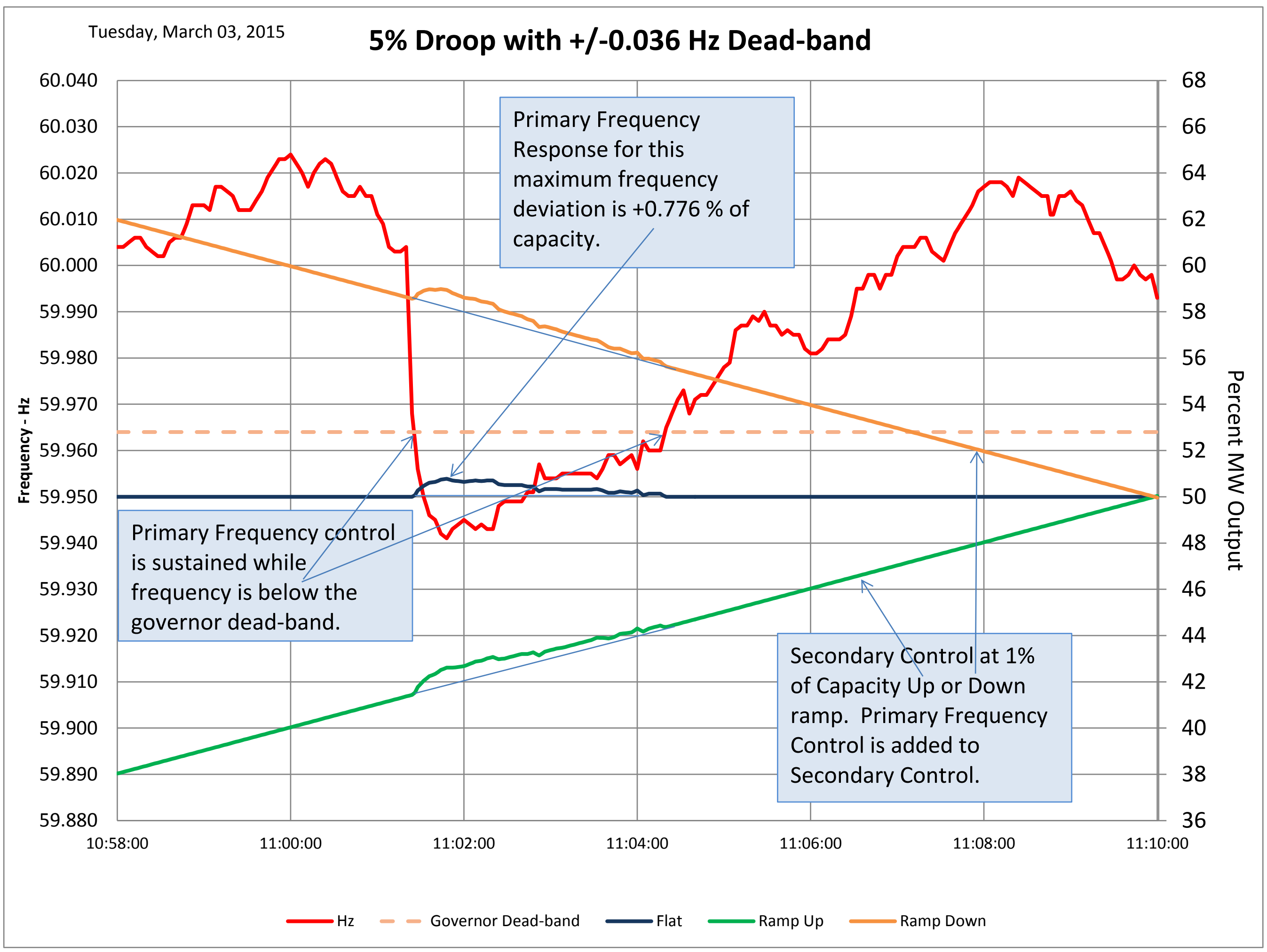
Figure 1: Typical High Level System

Closed loop load control will normally exist in at least one and possibly both load control loops. Frequency bias should be applied at the highest level of closed loop load control.

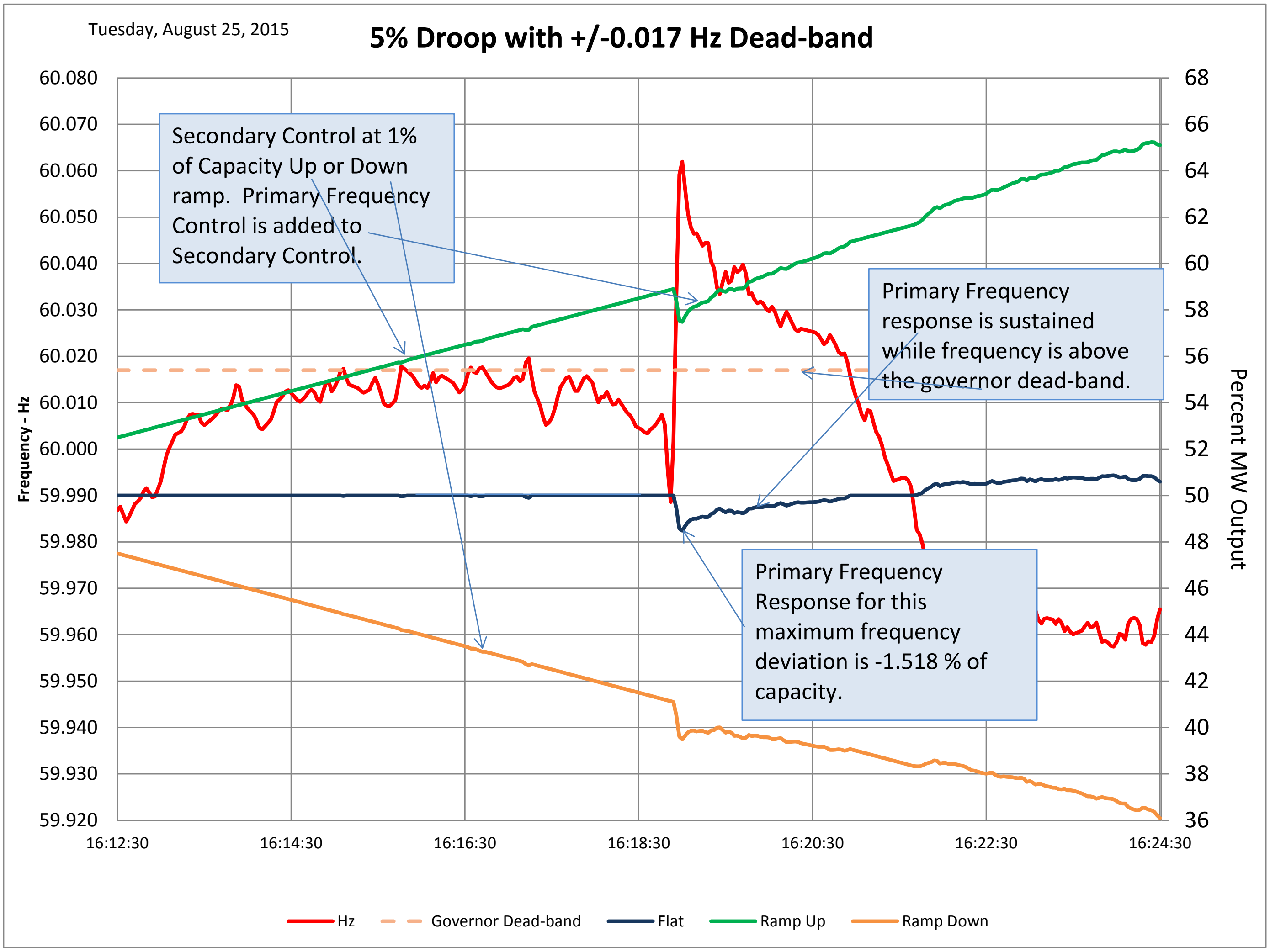
In order to understand the problem, it is necessary to study all layers of the load control system and verify that none of the layers undo the underlying governor response. This can generally be accomplished in several ways, including the following:

1. Use of a frequency bias in the plant level load controller would allow it to adjust individual load target in harmony with the governor response.
2. Use of a frequency bias in the turbine level load controls in conjunction with open loop load control at the plant level would allow the turbine control panel to adjust its internal load control target in harmony with the governor response.

   In both cases (1) and (2) the plant level load controls can adjust targets in response to external input, (e.g. a revised AGC target). Coordination of plant, turbine and governor controls dead bands and droop settings must also be coordinated as a system so as not to exceed the maximum recommended settings.
3. Operation of the unit in pure governor control with manual adjustments to the speed governor target such as analog or mechanical control systems and some early digital controllers typically include units that do not operate in any form of MW target control.



Example of Properly Coordinated Primary Frequency Control while ramping up or down via local or remote control or while operating at a fixed output.



Example of Properly Coordinated Primary Frequency Control while ramping up or down via local or remote control or while operating at a fixed output in the graph below - High Frequency excursion with a lower deadband

Governor Deadband and Droop

This guideline proposes maximum governor settings to achieve desired frequency response for each of the following Interconnections, subject to legitimate technical, operational, or regulatory considerations that would prevent governors from achieving the maximum governor settings. Although there are recommended governor deadband maximums for three of the Interconnections (36 mHz), it should be noted that deadbands of 17 mHz have been successfully implemented and efforts lowering deadbands to that level is encouraged. Similarly, deadbands are recommended to be implemented without a step to the droop curve, i.e. once outside the deadband the change in output starts from zero and then proportionally increases with the input. A more detailed discussion of the two methods can be found in Appendix B of "Dynamic Models for Turbine-Governors in Power System Studies" published by the IEEE PES in January 2013.

The recommended settings for each Interconnection are as follows:

Eastern Interconnection

A. Governor Settings – The following are recommended settings for governors or equivalent frequency control devices, subject to legitimate technical, operational, or regulatory considerations that would prevent governors from achieving the maximum governor settings.

1. **Deadband** –The deadband setting should not exceed +/- 36 millihertz (59.964 Hz to 60.036 Hz)
2. **Droop –** The droop setting should not exceed the following for each respective type of generator.

Generator Type	Max. Droop Setting %
Combined Cycle Facility[1]	
• Combustion Turbine	**4%**
• Steam Turbine	**5%**
Combustion Turbines[2]	**5%**
All Others	**5%**

[1] The maximum expected droop performance for the entire combined cycle facility is 6%. The combustion turbines should not exceed 4%.
[2] Many combustion turbines have a 4% droop setting which is within the maximum recommended setting.

ERCOT Interconnection

A. Governor Settings – The following are the BAL-001-TRE-1 requirements for deadband and droop settings.

1. Deadband –The deadband setting should not exceed the following :

Generator Type	Max. Deadband
Steam and Hydro Turbines with Mechanical Governors	**+/- 0.034 Hz**
All Other Generating Units/Generating Facilities	**+/- 0.017 Hz**

2. Droop – The droop settings should not exceed the following for each respective type of generator:

Generator Type	Max. Droop Setting %
Hydro	**5%**
Nuclear	**5%**
Coal and Lignite	**5%**
Combustion Turbine (Simple Cycle and Single-Shaft Combined Cycle)	**5%**
Combustion Turbine (Combined Cycle)	**4%**
Steam Turbine (Simple Cycle)	**5%**
Steam Turbine (Combined Cycle)	**5%**
Diesel	**5%**
Wind Powered Generator	**5%**
DC Tie Providing Ancillary Services	**5%**
Renewable (Non-Hydro)	**5%**

Western Interconnection

A. Governor Settings – The following are recommended settings for governors or equivalent frequency control devices, subject to legitimate technical, operational, or regulatory considerations that would prevent governors from achieving the maximum governor settings.

1. **Deadband** –The deadband setting should not exceed +/- 36 millihertz (59.964 Hz to 60.036 Hz)
2. **Droop –** The droop settings should not be less than 3% or greater than 5% and should not exceed the following for each respective type of generator:

Generator Type	Max. Droop Setting %
Combined Cycle Facility[3]	
• Combustion Turbine	**4%**
• Steam Turbine	**5%**
Combustion Turbines[4]	**5%**
All Others	**5%**

[3] The maximum expected droop performance for the entire combined cycle facility is 6%. The combustion turbines should not exceed 4%.
[4] Many combustion turbines have a 4% droop setting which is within the maximum recommended setting.

Quebec Interconnection

A. Governor Settings – The following are the recommended settings for governor frequency response:

1. **Deadband** – There should be no deadband on generators within the Quebec Interconnection.
2. **Droop –** The droop settings should be five percent for all types of generation within the Quebec Interconnection.

Performance Assessment

Some Balancing Authorities have developed methods for determining if prime mover governors are working properly by reviewing Energy Management System scan rate data (e.g., every four seconds) stored in their data historians (e.g., PI). Verification of the proper functioning of prime mover governors within a Balancing Authority can be time consuming and requires subject matter expertise. Balancing Authorities are strongly encouraged to evaluate the governor response being provided within their Balancing Authority Area. To assist in this effort, methods used successfully by some Balancing Authorities to address this task are presented below and may be used as a starting point for similar efforts of other Balancing Authorities.

The ERCOT Interconnection is a single Balancing Authority interconnection and has developed metrics to evaluate governor response performance. These metrics are included in the Regional Reliability Standard BAL-001-TRE-1, Attachment 2 “Primary Frequency Response Reference Document.” The attachment provides performance metric calculations for Initial Primary Frequency Response (section II), Sustained Primary Frequency Response (section III), and Limits on Calculation of Primary Frequency Response Performance (section IV). The first metric, described in section II, uses a fixed time interval to determine initial governor response to a frequency event. A second metric, described in section III, also uses a fixed time interval to determine if frequency response is being sustained. High scores on both metrics indicate that frequency response is being sustained, as desired. Low scores on both can indicate that frequency response is not being provided. Problems with outer loop control causing frequency response to be withdrawn (i.e., squelched response) can be indicated by a relatively high score in the first metric and a lower score in the second metric.

Several NPCC Balancing Authorities within the NPCC Region have used a graphical approach to determining if generator governor response is being sustained. Two plots of generator output and frequency are reviewed in the evaluation of a generator's response, along with some supplemental data. The first plot (starting five minutes before the decline in frequency and ending 15 minutes after the decline in frequency) is used to determine if other factors such as unit ramping or AGC control are occurring, which may invalidate the utility of the sample (it is not a "controlled" experiment). The second plot (starting one minute before the decline in frequency and ending two minutes after the decline in frequency) is used to determine the type of response observed and to calculate an observed droop if the response is being sustained. The analysis performed is a 3-step process: sample validation, response type classification, and droop verification. The process is explained further in Appendix A. A fixed time window is not used in the response type classification and droop verification, because Eastern Interconnection frequency deviations often persist for longer than one minute, and frequency response should be sustained until the frequency returns to a value within the governor deadband.

Historical Reference

The retired 2004 NERC Operating Policy 1, Generation Control and Performance, section C, stated:

1. Governor installation – Generating units with nameplate ratings of 10 MW or greater should be equipped with governors operational for frequency response unless restricted by regulatory mandates.
2. Governors free to respond – Governors should be allowed to respond to system frequency deviation unless there is a temporary operating problem.
3. Governor droop – All turbine-generators equipped with governors should be capable of providing immediate and sustained response to abnormal frequency excursions. Governors should provide a 5% droop characteristic. Governors should, at a minimum, be fully responsive to frequency deviations exceeding ±0.036 Hz (±36 millihertz).
4. Governor limits – Turbine control systems that provide adjustable limits to governor valve movement (valve position limit or equivalent) should not restrict travel more than necessary to coordinate boiler and turbine response characteristics.

Cited Documents

1. BAL-001-TRE-1
2. Frequency Response Initiative Report 2012
3. NERC Alert A-2015-02-05-01
4. IEEE PES Appendix B of "Dynamic Models for Turbine-Governors in Power System Studies"

Revision History:

Date	Version Number	Reason/Comments
12/15/2015	1.0	Initial Version – *Reliability Guideline: Primary Frequency Response*

Appendix A

Sample Validation, Response Type Classification, and Droop Verification

Sample Validation

There are several factors to be considered in determining if a particular declining frequency event can provide useful information about the frequency response of a particular generator. Any one of the following factors can reduce the confidence in or totally invalidate the performance sample.

- Improper data storage tolerances in the data historian
- Oscillatory generator output due to plant control tuning problems
- Generator is off line, ramping up or down due to dispatch instructions, or on AGC
- Output is at or near the generator high limit at the time of the frequency event
- Inaccuracy in the measurement of plant output
- Noisy telemetry of the output of the generator
- Actual high limit's sensitivity to ambient temperature versus a high limit provided based on forecasted temperature
- Higher levels of output is provided by equipment that is not frequency responsive (e.g., duct burners, steam injection)

Response Type Classification

Once a sample for a declining frequency event has been validated, an attempt is made to classify a sample as one of the following types based on a review of the plots of actual generation and frequency.

- Sustained - output increases after the frequency deviates below the governor deadband, with frequency response that is proportional to the ongoing frequency deviation beyond the governor deadband continuing until the frequency returns to be within the governor deadband.
- Squelched - output increases after the frequency deviates below the frequency deadband, but it decreases significantly in the direction of the output level that existed prior to the decline in frequency even though the frequency continues to be below the governor deadband.
- No Response - the output is essentially unchanged when the frequency deviates below the governor deadband.
- Negative Response - the output declines as the frequency declines, possibly due to thermal limitations or improper configuration of plant controls.

Individual samples are compared to determine an overall response type classification, and repeatability among samples is a key factor in this determination. A high degree of confidence in the overall classification can be developed when five to ten samples exhibit the same response type. However, an overall assessment of squelched response may require a greater number of samples, as the relative values of actual generation versus the desired dispatch level and its surrounding megawatt control deadband can result in a mixture of response types among samples. For example, out of 20 samples, six may appear to be sustained, six squelched, six no response, and two negative response.

Droop Verification

For generators classified as having sustained response, the droop and deadband settings can be verified. An expected output change for a declining frequency event can be computed based on generator size, droop setting, governor deadband, and the frequency observed when it is relatively stable during the event. This computed expected value can be compared with the actual observed change in output. Greater confidence in this verification can be achieved if the mean and median of about ten events are used in the comparison.

If the droop and deadband settings are not known, but there are about ten samples of sustained response, trial droop and deadband values can be used to estimate an effective droop/deadband pair by matching the mean and median of the observations with those expected for candidate droop/deadband pairs.

The empirical/effective droop settings can vary substantially for some conventional thermal generators based on load levels. For some generators, it may be desirable to compute different effective droop values for different output ranges. The droop rating is applicable to the entire operating range, while droop performance can vary depending on the initial load (and its corresponding governor valve position) when a frequency event occurs.