NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

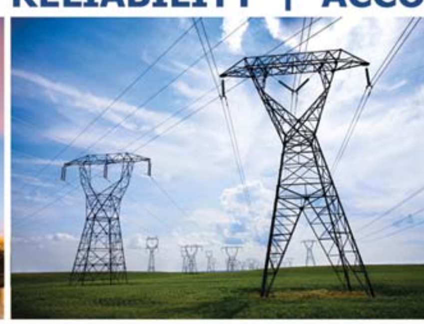
Frequency Response Initiative Report

The Reliability Role of Frequency Response

September 16, 2012 Draft

RELIABILITY | ACCOUNTABILITY



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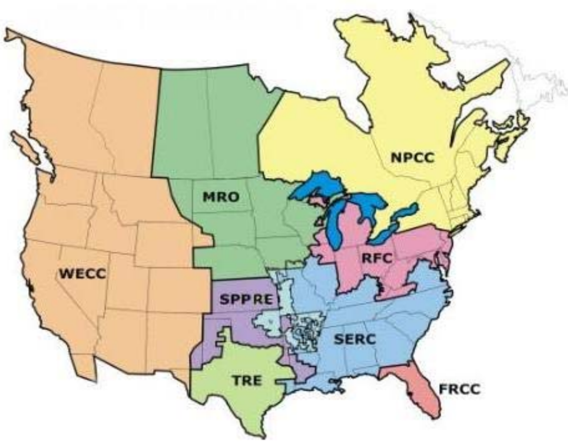
NERC's Mission

The North American Electric Reliability Corporation (NERC) is an international regulatory authority established to evaluate reliability of the bulk power system in North America. NERC develops and enforces Reliability Standards; assesses adequacy annually via a ten-year forecast and winter and summer forecasts; monitors the bulk power system; and educates, trains, and certifies industry personnel. NERC is the electric reliability organization for North America, subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada.[1]

NERC assesses and reports on the reliability and adequacy of the North American bulk power system, which is divided into eight Regional areas, as shown on the map and table below. The users, owners, and operators of the bulk power system within these areas account for virtually all the electricity supplied in the U.S., Canada, and a portion of Baja California Norte, México.



Note: The highlighted area between SPP RE and SERC denotes overlapping Regional area boundaries. For example, some load serving entities participate in one Region and their associated transmission owner/operators in another.

NERC Regional Entities	
FRCC Florida Reliability Coordinating Council	**SERC** SERC Reliability Corporation
MRO Midwest Reliability Organization	**SPP RE** Southwest Power Pool Regional Entity
NPCC Northeast Power Coordinating Council	**TRE** Texas Reliability Entity
RFC ReliabilityFirst Corporation	**WECC** Western Electricity Coordinating Council

[1] As of June 18, 2007, the U.S. Federal Energy Regulatory Commission (FERC) granted NERC the legal authority to enforce Reliability Standards with all U.S. users, owners, and operators of the bulk power system, and made compliance with those standards mandatory and enforceable. In Canada, NERC presently has memorandums of understanding in place with provincial authorities in Ontario, New Brunswick, Nova Scotia, Québec, and Saskatchewan, and with the Canadian National Energy Board. NERC standards are mandatory and enforceable in Ontario and New Brunswick as a matter of provincial law. NERC has an agreement with Manitoba Hydro making reliability standards mandatory for that entity, and Manitoba has recently adopted legislation setting out a framework for standards to become mandatory for users, owners, and operators in the province. In addition, NERC has been designated as the "electric reliability organization" under Alberta's Transportation Regulation, and certain reliability standards have been approved in that jurisdiction; others are pending. NERC and NPCC have been recognized as standards-setting bodies by the Régie de l'énergie of Québec, and Québec has the framework in place for reliability standards to become mandatory. Nova Scotia and British Columbia also have frameworks in place for reliability standards to become mandatory and enforceable. NERC is working with the other governmental authorities in Canada to achieve equivalent recognition.

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Introduction

System planning and operations experts are anticipating significantly higher penetrations of renewable energy resources, most of which are electronically-coupled to the grid, which presents some new and different technical challenges. Load management and other demand-side initiatives continue to grow. Most importantly, a continued downward trend for frequency response for several more years may produce credible contingencies that encroach on the first step of under-frequency load shedding (UFLS) or trigger undesirable reactions from frequency-sensitive "smart grid" loads or electronically-coupled renewable resources. Taken together, it is clear that frequency response poses a significant challenge for maintaining bulk power system reliability.

Various NERC activities have taken place over the past few years in an effort to understand the observed steady decline in frequency response, particularly in the Eastern Interconnection. While some significant insights had been gained system-wide and technical improvements achieved in the Western Interconnection and ERCOT, a deeper and more dedicated effort was needed.

To comprehensively address the issues related to frequency response, NERC launched the Frequency Response Initiative in 2010. In additional to coordinating the myriad of efforts underway in standards development and performance analysis, the initiative include performing in-depth interconnection-wide frequency response analysis to achieve a better understanding of the factors influencing frequency performance across North America.

Basic objectives of the Frequency Response Initiative include:

- Development of a clearer and more specific statement of frequency-related reliability factors, including better definitions for 'ownership' of responsibility for frequency response,
- Collection and provision of more granular data on and technical analyses of frequency-driven bulk power system events, including root cause analyses,
- Metrics and benchmarks to improve frequency response performance tracking,
- Increasing coordinated communication and outreach on the issue, to include webinars and NERC alerts, to share lessons learned, and
- Focused discussion on and communication of emerging technical and technology issues, including frequency-related effects caused by renewable energy integration, 'smart grid' technology deployment, and new end-use technology.

In March of 2011, the NERC Planning Committee tasked the Transmission Issues Subcommittee (TIS, now the System Analysis and Modeling Subcommittee – SAMS) to determine what criteria should be used to decide the appropriate level of interconnection-wide frequency response is needed for reliability. The TIS started with a body of work already underway by the Resources Subcommittee (RS) and the Frequency Working Group (FWG) of the Operating Committee, and the Frequency Response Standard Drafting Team (FRRSDT). The RS had produced a Position Paper on Frequency Response that was the basis for the method to translate a Resource Contingency Criteria into an Interconnection Frequency Response Obligation (IFRO).

That report on IFRO was approved by the Planning Committee in September, 2011.[2] Since that time, numerous modifications and improvements have been made to the IFRO determination analysis and calculations. Those changes are reflected in the IFRO section of this report.

This report provides an overview of the work that has been done to-date towards gaining understanding of Frequency Response, and in support of the standards development effort associated with Standards Project 2007-12 Frequency Response, which is preparing a revised draft standard (BAL-003). That standard is intended to codify a Frequency Response Obligation and means for measuring performance of the Balancing Authorities.

[2] http://www.nerc.com/docs/pc/tis/Agenda_Item_5.d_Draft_TIS_IFRO_Criteria%20Rev_Final.pdf

Executive Summary

Recommendations

1. NERC should embark immediately on the development of a NERC turbine-generator governor Guideline calling for deadbands of ±16.67 mHz with droop settings of 4%-5% depending on turbine type. This effort is aimed at retaining or regaining frequency response capabilities of the existing generator fleet.

2. The calculation of the Interconnection Frequency Response Obligations should use statistical analysis to determine the necessary margin instead of a fixed margin.

3. The Starting Frequency for the calculation of IFROs should be frequency of the 5% of lower tail samples from the statistical analysis, representing a 95% confidence that frequencies will be at or above that value at the start of any frequency event, as shown in Table A.

Table A: Interconnection Frequency Variation Analysis (Hz)				
Value	Eastern	Western	ERCOT	Québec
Starting Frequency (F_{Start})	**59.973**	**59.977**	**59.961**	**59.971**

4. Using the tenet that UFLS should not trip for a frequency event throughout the interconnection the recommended UFLS first-step limitations for IFRO calculations are listed in Table B.

Table B: Low Frequency Limits (Hz)	
Interconnection	Highest UFLS Trip Frequency
Eastern	59.7
Western	59.5
ERCOT	59.3
Québec	58.5

5. The allowable frequency deviation (starting frequency minus the highest UFLS step) should be reduced to account for differences between the 1-second and sub-second data for Point C (frequency nadir) by a statistically-determined adjustment as listed in Table C. Sub-second measurements will more accurately detect the Point C.

Table C: Analysis of 1-Second and Sub-Second Data for Point C (CC_{ADJ})				
Interconnection	Number of Samples	Mean	Standard Deviation	CC_{ADJ} (95% Quantile)
Eastern	30	0.0006	0.0038	0.0068
Western	17	0.0012	0.0019	0.0044
ERCOT	58	0.0021	0.0061	0.0121
Québec	0	N/A	N/A	N/A

6. The allowable change in frequency from the IFRO starting frequency should be adjusted by a statistically-determined value to account for the differences between the Value B and the Point C for historical frequency events as listed in Table D

Table D: Analysis of Value B and Point C (CB_R)				
Interconnection	Number of Samples	Mean	Standard Deviation	CB_R (95% Quantile)
Eastern	41	0.964	0.0149	1.0 (0.989)[3]
Western	30	1.570	0.0326	1.625
ERCOT	88	1.322	0.0333	1.377
Québec	26	3.280	0.1952	3.613

[3] CB_R value limited to 1.0 because values lower than that indicate the Value B is lower than Point C and does not need to be adjusted. The calculated value is 0.989.

7. The Interconnection Frequency Response Obligations should be calculated as shown in Table E: Recommended IFROs.

Table E: Recommended IFROs					
	Eastern	**Western**	**ERCOT**	**Québec**	
Starting Frequency	59.973	59.977	59.961	59.972	Hz
Minimum Frequency Limit	59.700	59.500	59.300	58.500	Hz
Base Delta Frequency	0.273	0.477	0.661	1.472	Hz
CC_{ADJ}	0.007	0.004	0.012	N/A	Hz
Delta Frequency$_{-C}$	0.266	0.473	0.649	1.472	Hz
CB_R	1.000[4]	1.625	1.377	3.613	Hz
Max. Delta Frequency (DF_{CC}/CB_R)	0.266	0.291	0.471	0.407	Hz
Resource Contingency Protection Criteria	4,500	2,740	2,750	1,700	MW
Credit for LR		300	1,400		MW
IFRO	-1,692	-838	-286	-417	MW/0.1Hz
Absolute Value of IFRO	1,692	838	286	417	MW/0.1Hz
% of Current Interconnection Performance[5]	68.6 %	71.0 %	48.9 %	N/A	
% of Interconnection Load[6]	0.28 %	0.56 %	0.45 %	2.03 %	

8. NERC and the Western Interconnection should analyze the FRO allocation implications of the Pacific Northwest RAS generation tripping of 3,200 MW.

9. Trends in Frequency Response sustainability should be measured and tracked by observing frequency between T+45 seconds and T+180 seconds. A pair of indices for gauging sustainability should be calculated comparing that value to both the Point C and Value B.

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4 CB_R value for the Eastern Interconnection limited to 1.0 because values lower than that indicate the Value B is lower than Point C and does not need to be adjusted. The calculated value is 0.989.

5 Current Interconnection Frequency Response Performance: EI = -2,467 MW / 0.1Hz, WI = -1,179 MW / 0.1Hz, TI = -586 MW / 0.1Hz, and QI = N/A.

6 Interconnection projected Total Internal Demands from the 2010 NERC Long-Term Reliability Assessment: EI = 604,245 MW, WI = 148,895 MW, TI = 63,810 MW, and QI = 20,599 MW.

10. Frequency Response performance by Balancing Authorities should not be judged for compliance on a per-event basis.

11. Linear Regression is the method that should be used for calculating Balancing Authority Frequency Response Measure (FRM) for compliance with Standard BAL-003 – Frequency Response.

12. NERC and the Frequency Working Group should annually review the process for detection of frequency events and the calculation of Values A, B, and C. The associated interconnection level metrics and the calculation of the IFROs using updated data should also undergo review in an effort to improve the process.

13. NERC should address improving the level of understanding of the role of generator governors through seminars and webinars, with educational materials available to the Generator Owners and Generator Operators on an ongoing basis.

14. When ERAG MMWG completes its review of generator governor modeling, a new light-load case should be developed and the resource loss criterion for the interconnections IFRO should be re-simulated.

15. Eastern Interconnection inter-area oscillatory behavior should be further investigated by NERC, including the testing of large resource loss analysis for IFRO validation.

Findings

1. Analysis of data submitted by the Balancing Authorities during the field trial indicates that a single event based compliance measure is unsuitable for compliance evaluation when based on data that has the large degree of variability demonstrated by the field trial.

2. Analysis of data submitted by the Balancing Authorities during the field trial confirms that the sample size selected (a minimum of 20 to 25 frequency events) is sufficient to stabilize the result and alleviate the perceived problem associated with outliers in the measurement of Balancing Authority Frequency Response performance.

3. There is a strong positive correlation between Eastern Interconnection Load and Frequency Response for the 2009-2011 events. On average, when Interconnection Load changes by 1,000 MW, Frequency Response changes by 3.5 MW/0.1Hz.

4. Pre-disturbance frequency (Value A) is a statically significant contributor to the variability of Frequency Response for the Eastern Interconnection. The expected (mean of the sample) Frequency Response for events where Value A is greater than 60 Hz is 2,188 MW/0.1 Hz versus 2,513 MW/0.1 Hz for events where Value A is less than or equal to 60 Hz based on data from 2009 through April 2012.

5. There is a statistically significant seasonal (Summer/Not summer) correlation to the variability of Frequency Response for the Eastern Interconnection. The expected Frequency Response for summer (June-August) frequency events is 2,598MW/0.1 Hz versus 2,271 MW/0.1 Hz for non-summer events based on data from 2009 through April 2012.

6. The difference in average Frequency Response between On-Peak events and Off-Peak events is not statistically significant for the Eastern Interconnection and could occur by chance.

Frequency response Overview

Frequency Control

To understand the role Frequency Response plays in system reliability, it is important to understand the different components of frequency control and the individual components of Primary Frequency Control, also known as Frequency Response. It is also important to understand how those individual components relate to each other.

Frequency control can be divided into four overlapping windows of time:

Primary Frequency Control (Frequency Response) – Actions provided by the Interconnection to arrest and stabilize frequency in response to frequency deviations. Primary Control comes from automatic generator governor response, load response (typically from motors), and other devices that provide an immediate response based on local (device-level) control systems.

Secondary Frequency Control – Actions provided by an individual Balancing Authority or its Reserve Sharing Group to correct the resource – load unbalance that created the original frequency deviation, which will restore both Scheduled Frequency and Primary Frequency Response. Secondary Control comes from either manual or automated dispatch from a centralized control system.

Tertiary Frequency Control – Actions provided by Balancing Authorities on a balanced basis that are coordinated so there is a net zero effect on Area Control Error (ACE). Examples of Tertiary Control include dispatching generation to serve native load; economic dispatch; dispatching generation to affect Interchange; and re-dispatching generation. Tertiary Control actions are intended to replace Secondary Control Response by reconfiguring reserves.

Time Control – This includes small offsets to scheduled frequency to keep long term average frequency at 60 Hz.

Primary Frequency Control – Frequency Response

Primary Frequency Control, also known generally as Frequency Response, is the first stage of overall frequency control and is the response of resources and load to arrest that locally sensed changes in frequency. Primary Frequency Response is automatic, is not driven by any centralized system, and begins within seconds after the frequency changes rather than minutes. Different resources, loads, and systems provide Primary Frequency Response with different response times, based on current system conditions such as total resource/load mix and characteristics.

The NERC Glossary of Terms defines Frequency Response in two parts as:

- **(Equipment)** The ability of a system or elements of the system to react or respond to a change in system frequency.
- **(System)** The sum of the change in demand, plus the change in generation, divided by the change in frequency, expressed in megawatts per 0.1 Hertz (MW/0.1 Hz).

As noted above, Frequency Response is the characteristic of load and generation within Balancing Authorities and Interconnections that reacts or responds with changes in power to variations in the load-resource balance that appear as changes to system frequency. Because the loss of a large generator is much more likely than a sudden loss of an equivalent amount of load, Frequency Response is typically discussed in the context of a loss of generation.

Frequency Response Illustration

Included within Frequency Response are many components that make up that response. The following simplified example illustrates the components of Frequency Response in graphical form. It includes a series of seven graphs that display the components of Frequency Response and how they react to changes in system frequency. The example is presented as an energy balance problem for the interconnection. It is not intended to be a treatise on governors or other turbine-generator controls or the internal machine dynamics associated with those control actions. For additional information on those topics, see the references on rotating machines section in Appendix L.

The simplified example is based on an assumed disturbance event due to the sudden loss of 1,000 MW of generation. Although a large event is used to illustrate the response components, even small events can result in similar reactions or responses. The magnitude of the event only affects the shape of the curves on the graph; it does not preclude the need for Frequency Response.

The loss of generation is illustrated by the black power deficit line using the MW scale on the left. The interconnection Frequency is illustrated in red, using the Hertz (Hz) scale on the right. The interconnection Frequency is assumed to be 60 Hz when the disturbance occurs.

Figure 1 shows the tripping of a 1,000 MW generator. Even though the generation has tripped and power injected by the generator has been removed from the interconnection, the loads continue to use the same amount of power. The "Law of Conservation of Energy" requires that the 1,000 MW must be supplied to the interconnection, which is extracted from the kinetic energy stored as inertial energy in the rotating mass of all of the synchronized generators and motors on the interconnection. The energy extracted from the inertial energy of the interconnection provides the Balancing Inertia to maintain the power and energy balance on the interconnection. As this Balancing Inertia is used, the speed of the rotating equipment on the interconnection declines, resulting in a reduction of the interconnection frequency.

Figure 1: Loss of a 1,000 MW Generator

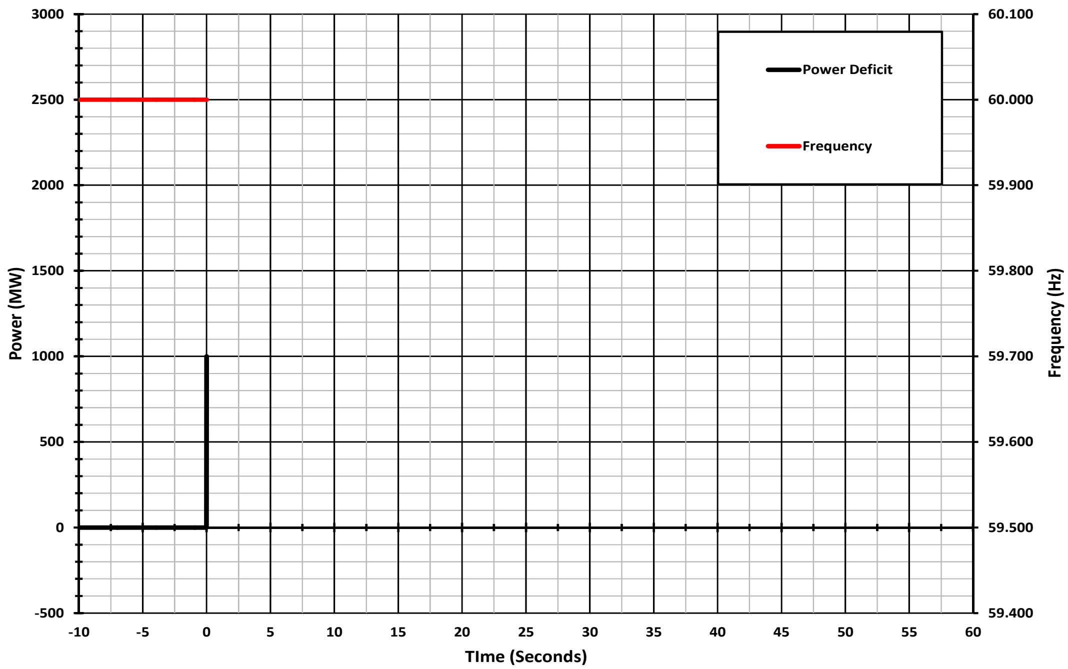
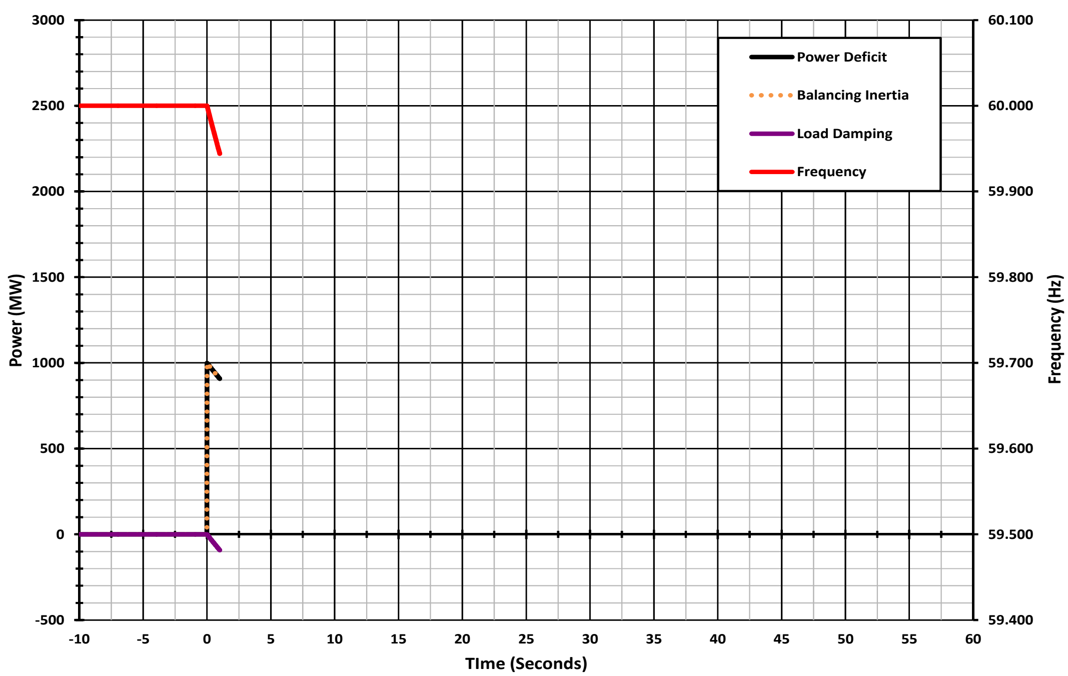


Figure 2: Inertial Energy Extracted from Rotating Mass of Generation and Synchronous Motor Load



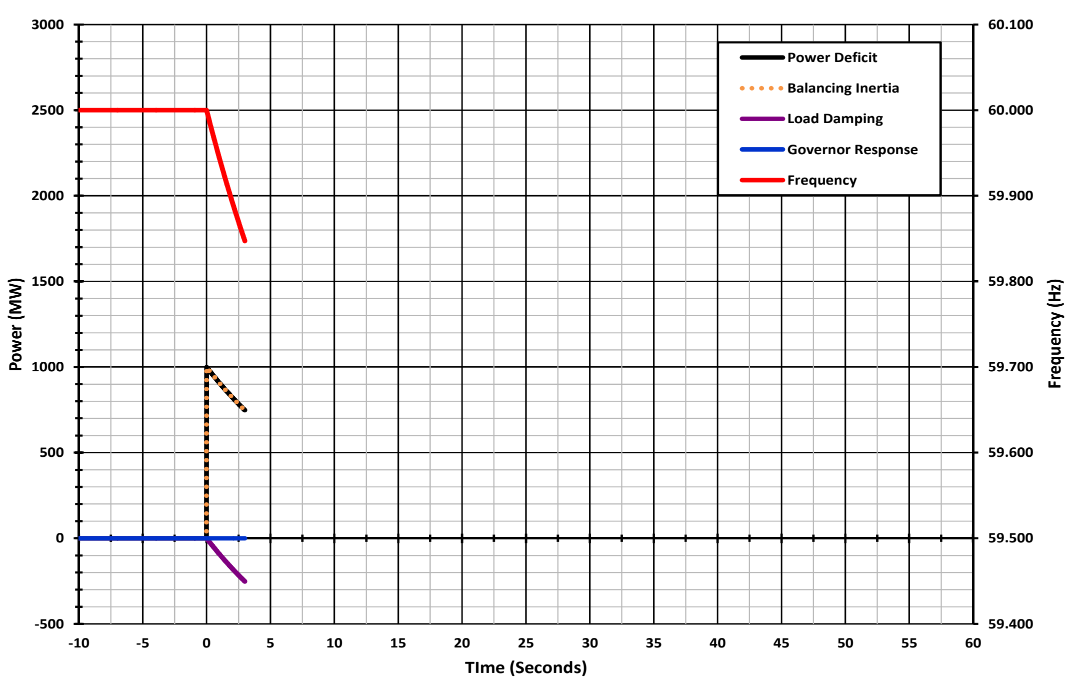
Only synchronously operated motors contribute to Load Damping; adjustable or variable speed drive motors are effectively decoupled from the interconnection frequency through their electronic controls, and they do not contribute to Load Damping. In general, any load that does not change with interconnection frequency, such as resistive loads, will not contribute to Load

Damping or Frequency Response. In accordance with the laws of physics, the amount of energy extracted from rotating machines as Balancing Inertia exactly equals the power deficit, thus indicating that there is no power or energy imbalance at any time during the process. At this point in the example, no other energy injection has yet to occur through any governor control action.

As the rotating machines slow down, reflected as a decline of frequency, the generator governors, which are the controls that "govern" the speed of the generator turbines, sense this as a change in turbine speed. In this example, the change in frequency will be used to reflect this control parameter. Governor action then takes physical action such as injecting more gas into a gas turbine, opening steam valves wider on a steam unit (also injecting more fuel into the boiler), or opening the control gates wider on a hydraulic turbine. This control action results in more combusted gases, steam, or water to impart more mechanical energy to the shaft of the turbine to increase its speed. The turbine shaft is coupled to the generator where it is converted into additional electric energy. The time it takes for the turbine to slow, the change in speed to be detected, and the additional mechanical energy to be injected is not instantaneous.

Until the additional mechanical energy can be injected, the frequency continues to decline due to the ongoing extraction of Balancing Inertia power and energy from the rotating turbine generators and synchronous motors on the interconnection. As frequency continues to decline, the reduction in load also continues as the effect of Load Damping continues to reduce the load.

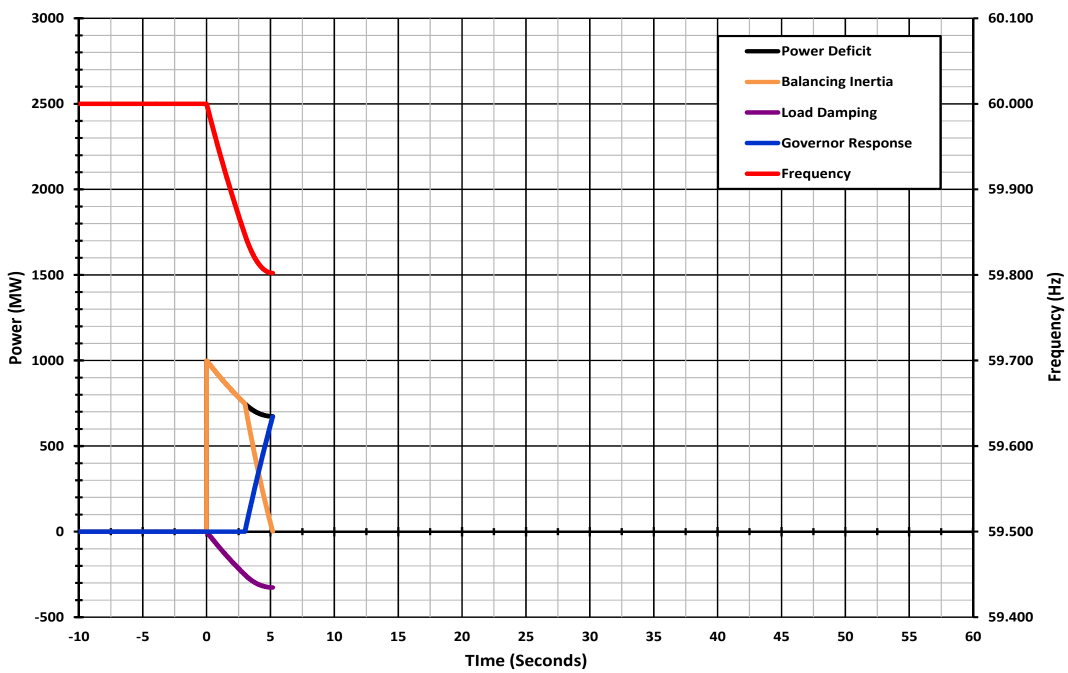
Figure 3: Time Delay of Governor Response



For this example, Governor Response that injects additional energy into the system is reflected by the blue line (in MW) on Figure 3.

After a short time delay, the Governor Response begins to increase rapidly in response to the initial decline in frequency, as illustrated on the Figure 4. In order to arrest the frequency decline, the Governor Response must offset the power deficit and replace the Balancing Inertia power to stop the extraction of inertial energy from the rotating machines of the interconnection. At this point in time, the Balancing Inertia has provided its contribution to reliability and its power contribution is reduced to zero as it is replaced by the Governor Response. That replacement is shown as the crossing of the orange and blue lines in Figure 4. The point at which the frequency decline is arrested is called the nadir or Point C.

Figure 4: Governor Response Replaces Balancing Inertia and Arrests Frequency Decline



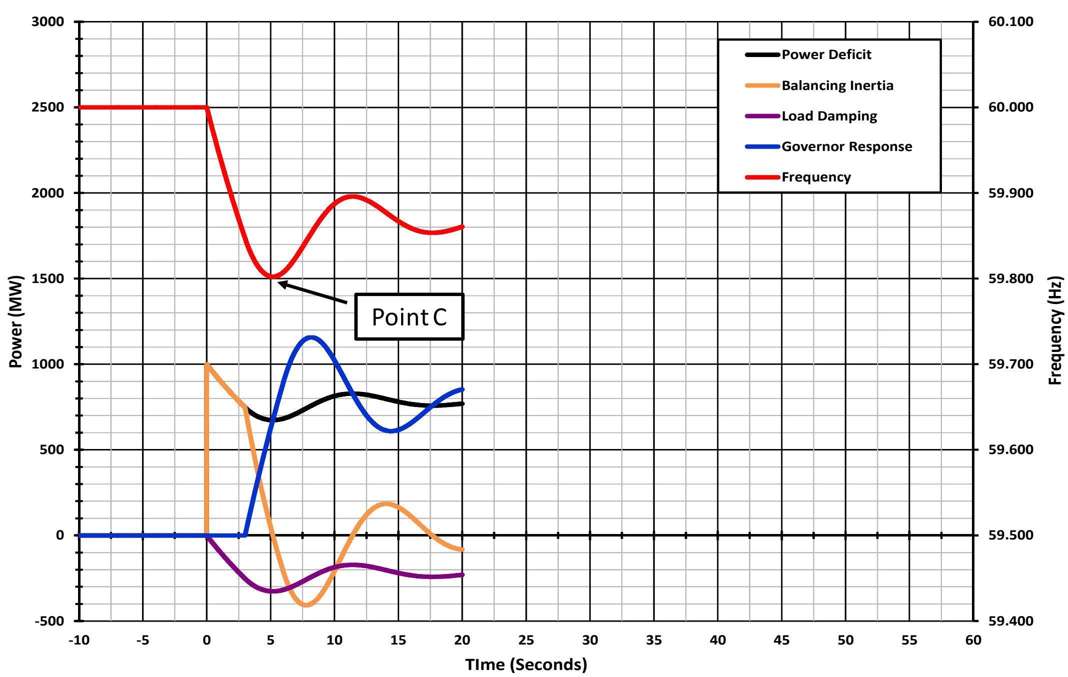
If the time delay associated with the delivery of Governor Response is reduced, the amount of Balancing Inertia required to limit the change in frequency for the disturbance event can also be reduced. This supports the conclusion that Balancing Inertia is required to manage the time delays associated with the delivery of Frequency Response. Not only is the rapid delivery of Frequency Response important, the shortening of the time delay associated with its delivery is also important. Therefore, two important components of Frequency Response are related to the length of time before the initial delivery of Governor Response begins and how much of the response is delivered before the frequency change is arrested.

From a system standpoint during this time delay, the amount of inertia on the interconnection available to be extracted from rotating machines determines the slope of the frequency decline – the less inertia there is, the steeper the slope. This is important in the relationship between the Balancing Inertia and the time delay associated with the Governor Response. For a given time delay in Governor Response, the steeper the slope, the lower frequency will dip before it is arrested. Conversely, for a given Balancing Inertia and slope of frequency decline, the faster Governor Response can be provided, the sooner the frequency decline is arrested, making the nadir less severe.

Therefore, as traditional rotating generators are replaced by electronically coupled resources, such as wind turbines and solar voltaic resources, which provide less overall system inertia, the speed of delivery of Governor Response should increase or other methods be provided that support fast-acting energy injection to minimize the depth of frequency excursions.

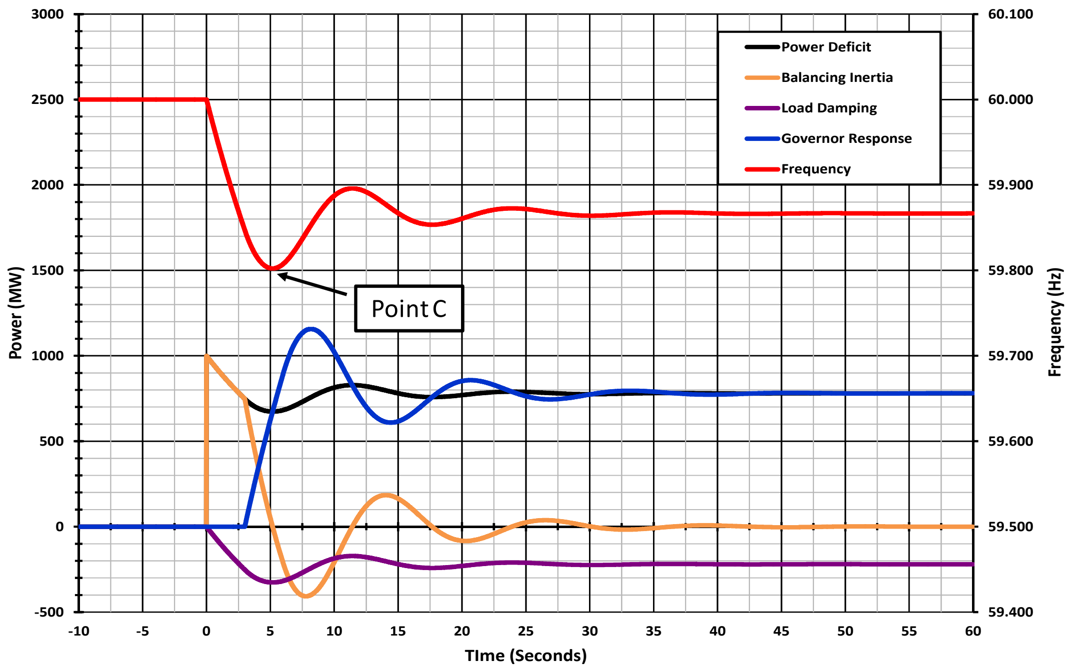
The nadir of the frequency deviation, at which the frequency is first arrested, is defined as Point C and Frequency Response calculated at this point is called the "Arrested Frequency Response." The Arrested Frequency is normally the minimum (maximum for load loss events) frequency that will be experienced during a disturbance event. This minimum frequency is the frequency that is of concern from a reliability perspective. The goal is to arrest the frequency decline so frequency remains above the under-frequency load shedding (UFLS) relays with the highest settings so that load is not tripped. Frequency Response delivered after frequency is arrested at this minimum provides less reliability value than Frequency Response delivered before Point C, but greater value than Secondary Frequency Control power and energy which is delivered minutes later.

Figure 5: Post-Disturbance Transient Period (0 to 20 seconds)



Once the frequency decline is arrested, the governors continue to respond because of the time delay associated with their Governor Response. This results in the frequency partially recovering from the minimum arrested value and results in an oscillating transient that follows the minimum frequency (Arrested Frequency) until power flows and frequency settle during the transient period that ends around 20 seconds after the disturbance event. This post-disturbance transient period is shown in Figure 5.

Figure 6: Disturbance Event Frequency Excursion



The total disturbance event illustration is presented in Figure 6. Frequency and power contributions stabilize at the end of the transient period. Frequency Response calculated from data measured during this settled period is called the "Settled Frequency Response." The Settled Frequency Response is the measure used as an estimator for determining the "Frequency Bias Setting" used in the automated generator control (AGC) systems of the energy management systems (EMS) in energy control centers.

Figure 7: Averaging Periods used for Measuring Frequency Response

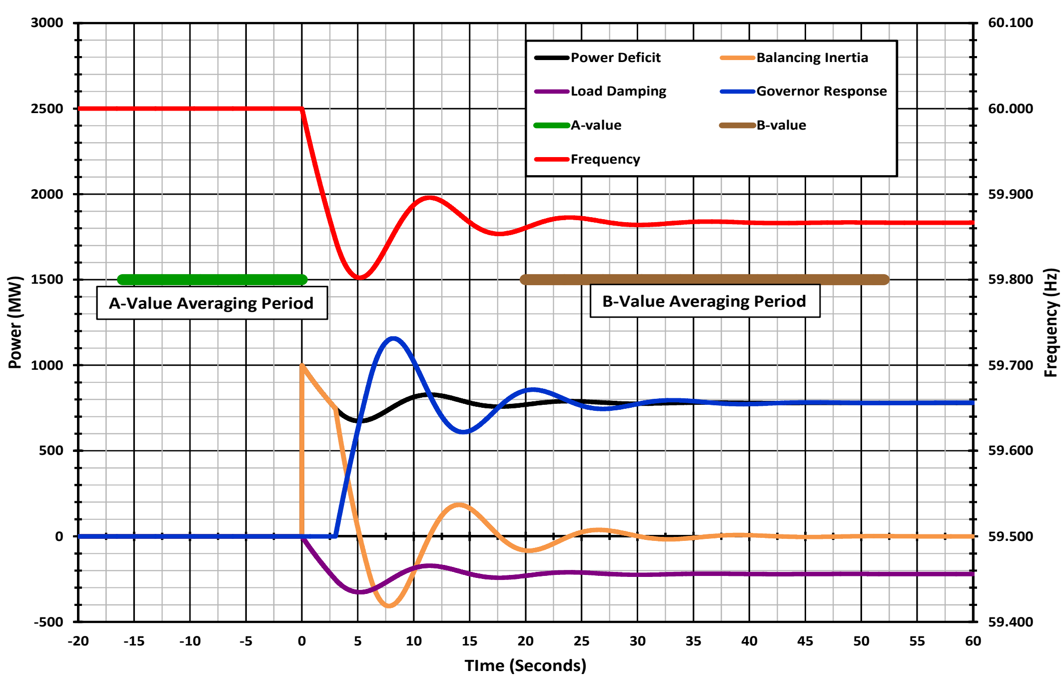


Figure 7 shows the averaging periods used to estimate the pre-disturbance A-Value Averaging Period and the post-disturbance B-Value Averaging Period used to calculate the Settled Frequency Response. A detailed discussion of the measurement of Frequency Response and the factors that affect the methods chosen to measure Frequency Response for implementation in a reliability standard are contained in the Frequency Response Performance Measurement section of this document.

Balancing Authority Frequency Response

Disturbances can cause the frequency to either increase from loss of load or decrease from loss of generation; frequency response characteristics of Balancing Authorities should be evaluated for both types of events.

Accurate measurement of frequency response for an Interconnection or for individual Balancing Authorities is difficult unless the frequency deviation resulting from a system disturbance is significant.

Therefore, it is better to analyze response only when significant frequency deviations occur.

1. **Frequency Response Characteristic** — For any change in generation/load balance in the Interconnection, a frequency change occurs. Each Balancing Authority in the Interconnection will respond to this frequency change through:

   - A load change that is proportional to the frequency change due to the load's frequency response characteristic, and
   - A generation change that is inverse to the frequency change due to turbine governor action. The net effect of these two actions is the Balancing Authority's response to the frequency change, that is, its frequency response characteristic (FRC). The combined response of all Balancing Authorities in the Interconnection will cause the Interconnection frequency to settle at some value different from the pre-disturbance value. It will not return frequency to the pre-disturbance value because of the turbine governor droop characteristic. Frequency will remain different until the Balancing Authority with the generation/load imbalance (referred to as the "contingent Balancing Authority") corrects that imbalance, thus returning the Interconnection frequency to its pre-disturbance value.

2. **Response to Internal and External Generation/Load Imbalances —** Most of a Balancing Authority's frequency response will be reflected in a change in its actual net interchange. By monitoring the frequency error (the difference between actual and scheduled frequency) and the difference between actual and scheduled interchange, using its response to frequency deviation, a Balancing Authority's automatic generation control (AGC) can determine whether the imbalance in load and generation is internal or external to its system. If internal, the Balancing Authority's AGC should correct the imbalance. If external, the Balancing Authority's AGC should allow its generator governors to continue responding (preserved by its frequency bias contribution in its

ACE equation) until the contingent Balancing Authority corrects its imbalance, which should return frequency to its pre-disturbance value.

3. **Frequency Bias versus Frequency Response Characteristic (FRC)** — The Balancing Authority should set its bias setting in its AGC ACE equation to match its FRC. In doing so, the Balancing Authority's bias contribution term would exactly offset the tie line flow error (NiA – NiS) of the ACE that results from governor action following a frequency deviation on the Interconnection. The following sections discuss the effects of bias settings on control action and explain the importance of setting the bias equal to the Balancing Authority's FRC. The discussion explains the control action on all Balancing Authorities external to the contingent Balancing Authority (the Balancing Authority that experienced the sudden generation/load imbalance) and on the contingent Balancing Authority itself.

   While this discussion deals with loss of generation, it applies equally to loss of load, or any sudden contingency resulting in a generation/load mismatch. Each Balancing Authority's frequency response will vary with each disturbance because generation and load characteristics change continuously. This discussion also assumes that the frequency error from 60 Hz was zero (all ACE values were zero) just prior to the sudden generation/load imbalance.

4. **Effects of a Disturbance on all Balancing Authority External to the Contingent Balancing Authority** — When a loss of generation occurs, an Interconnection frequency error will occur as rotating kinetic energy from the generators of the interconnection is expended, slowing the generators throughout the interconnection. All Balancing Authorities' generator governors will respond to the frequency error and increase the output of their generators (increase speed) accordingly. This will cause a change in the Balancing Authorities' actual net interchange. In other words, the Actual Net Interchange (Ni_A) will be greater than the Scheduled Net Interchange (Ni_S) for all but the contingent Balancing Authority, and the result is a positive flow out of the non-contingent Balancing Authorities. The resulting tie flow error (Ni_A – Ni_S) will be counted as Inadvertent Interchange.

   If the Balancing Authorities were using only tie line flow error (i.e., flat tie control ignoring the frequency error), this non-zero ACE would cause their AGC to reduce generation until Ni_A was equal to Ni_S; returning their ACE to zero. However, doing this would not help arrest Interconnection frequency decline because the Balancing Authorities would not be helping to temporarily replace some of the generation deficiency in the Interconnection. With the tie-line bias method, the Balancing Authorities' AGC should allow their governors to continue responding to the frequency deviation until the contingent Balancing Authority replaces the generation it has lost.

   In order for the AGC to allow governor action to continue to support frequency, a frequency bias contribution term is added to the ACE equation to counteract the tie flow error. This bias contribution term is equal in magnitude and opposite in direction to the governor action and should ideally be equal to each Balancing Authority's frequency response characteristic measured in MW/0.1 Hz. Then, when multiplied by the frequency error, the bias should exactly counteract the tie flow error portion of the ACE calculation, allowing the allowing the continued support of the generator governor action to support system frequency.

In other words, $BiasContributionTerm = 10B(f_A - f_S)$. ACE will be zero, and AGC will not readjust generation.

The ACE equation is then:

$$ACE = (Ni_A - Ni_S) - 10B(f_A - f_S) - I_{ME}$$

Where:

- The factor 10 converts the bias setting (B) from MW/0.1 Hz to MW/Hz.
- I_{ME} is meter error correction estimate; this term should normally be very small or zero.

NOTE: When people talk about Frequency Response and Bias, they often discuss them as positive values (such as “our Bias is 50 MW/0.1 Hz”). Frequency Response and Bias are actually negative values.

If the bias setting is greater than the Balancing Authority’s actual frequency response characteristic (FRC), then its AGC will increase generation beyond the primary governor response, which further helps arrest the frequency decline, but increases Inadvertent Interchange. Likewise, if the bias contribution term is less than the actual FRC, its AGC will reduce generation, reducing the Balancing Authority’s contribution to arresting the frequency change. In both cases, the resultant control action is unwanted.

5. **Effects of a Disturbance on the Contingent Balancing Authority** — In the contingent Balancing Authority where the generation deficiency occurred, most of the replacement power comes from the Interconnection over its tie lines from the frequency bias contributions of the other Balancing Authorities in the Interconnection. A small portion will be made up internally from the contingent Balancing Authority’s own governor response. In this case, the difference between NiA and NiS for the contingent Balancing Authority is much greater than its frequency bias component. Its ACE will be negative (if the loss is generation), and its AGC will begin to increase generation.

- Ni_A — drops by the total generation lost less the contingent Balancing Authority’s own governor response
- Ni_S — does not change

The contingent Balancing Authority must take appropriate steps to reduce its ACE to zero or predisturbance ACE if ACE is negative within fifteen minutes of the contingency. (Reference: formerly Operating Criterion II.A.) The energy supplied from the Interconnection is posted to the contingent Balancing Authority’s inadvertent balance.

6. **Effects of a Disturbance on the Contingent Balancing Authority with a Jointly-Owned Unit** — In the contingent Balancing Authority where the generation deficiency occurred on a jointly-owned unit (with dynamically scheduled shares being exported), the effects on the tie line component (Ni_A – Ni_S) of their ACE equation are more complicated. The NiA drops by the total amount of the generator lost, while the NiS is reduced only by the dynamic reduction in the shares being exported.

   - NiA — drops by the total generation lost less the contingent Balancing Authority's own governor response
   - Ni_S — decreases by the reduction in dynamic shares being exported

   The net effect is that the tie line bias component only reflects the contingent Balancing Authority's share of the lost generation. Most of the replacement power comes from the Interconnection over its tie lines from the frequency bias contributions of the other Balancing Authorities in the Interconnection.

7. **Effects of a Disturbance on the Non-Contingent Balancing Authority with a Jointly-Owned Unit** — In the non-contingent Balancing Authority where the generation deficiency occurred on a jointly-owned unit in another Balancing Authority (with dynamically scheduled shares being exported), the effects on the tie line component (Ni_A – Ni_S) of their ACE equation are also complicated. The Ni_A increases by Balancing Authority's own governor response, while the Ni_S is reduced only by the dynamic reduction in the shares being imported.

   - Ni_A — increases by the Balancing Authority's own governor response
   - NiS — decreases by withdrawn dynamic shares of the jointly-owned unit.

   The net effect is that the tie line bias component only reflects the contingent Balancing Authority's share of the lost generation. Most of the replacement power comes from the Interconnection over its tie lines from the frequency bias contributions of the other Balancing Authorities in the Interconnection.

Historical Frequency Response Analysis

History of Frequency Response and its Decline

Interconnection Frequency Response has been a subject of industry interest and attention since the first two electric systems became interconnected and the concept of frequency bias was adopted. In 1942, the first test to determine the system's load/frequency characteristic was conducted for use in setting bias control. As interconnected systems grew larger, and the characteristics of load and generation changed, it became apparent that guidelines were needed regarding Frequency Response to avoid one system imposing undue frequency regulation burdens on its interconnected neighbors. During the 1970s and 1980s, NERC's Performance Subcommittee (now the Resources Subcommittee of the Operating Committee), charged with monitoring the control performance of the interconnections observed that generator's governor responses to frequency deviations had been decreasing especially in the Eastern Interconnection. The result was quite noticeable during large generation losses where the frequency deviation was not arrested as quickly as it once was. The industry did not initially recognize that power systems operations could significantly influence primary Frequency Response.[7]

In 1991, NERC's Performance Subcommittee approached the Electric Power Research Institute ("EPRI") with a request to fund and manage a study of the apparent decline in governor response in the Interconnections. EPRI agreed and in turn contracted with EPIC Engineering to perform this study. The conclusions were captured in a joint EPRI/NERC report, *Impacts of Governor Response Changes on the Security of North American Interconnections*.[8] These studies indicated that the Frequency Response of the interconnections was declining at rates greater than would be expected with the growth of demand and generating capacity.[9] Although Frequency Response was declining, the opinion of experts at the time was that the decline had not reached a point where reliability was being compromised.

The NERC Resources Subcommittee proposed a Frequency Response Standard for comment in 2001. In response to these comments, the Frequency Task Force of the NERC Resources Subcommittee published a *Frequency Response Standard Whitepaper*[10] intended to create an understanding of the need for a Frequency Response standard and the technical and economic

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7 *See* Illian, H.F. *Frequency Control Performance Measurement and Requirements*, LBNL-4145E (December 2010).

8 EPRI Report TR-101080, *Impacts of Governor Response Changes on the Security of North American Interconnections*, October 1992.

9 *See* EPRI Report TR-101080, *Impacts of Governor Response Changes on the Security of North American Interconnections*, October 1992 ("An analysis of the 14 Frequency Response Characteristics Surveys conducted by NERC over the 1971 to 1993 period showed that the Frequency Response in percent MW/O. 1Hz has deteriorated. This value in 1971 was between 2.25 to 3.25% (depending on the area) and by 1993 had dropped to 0.75 and 1.25 %.").

10 Available here: http://www.nerc.com/docs/oc/rs/Frequency_Response_White_Paper.pdf ("Frequency Response Standard Whitepaper").

drivers motivating its development. The paper documented and discussed the decline observed in Frequency Response in the Eastern and Western Interconnections.

Projections of Frequency Response Decline

In August 2011, the Transmission Issues Subcommittee[11] of the NERC Planning Committee completed an analysis *Interconnection Criteria for Frequency Response Requirements – Determination of Interconnection Frequency Response Obligations*.[12] The analysis included comparisons of various Resource Contingency Protection Criteria for loss of resources, including: largest potential loss-of-resource event (N-2), the largest total generating plant with common voltage switchyard, and the largest loss of generation in the interconnection in the last 10 years. Also examined in that analysis were the various other factors that must be considered in an IFRO determination: the highest underfrequency load shedding ("UFLS") program setpoint within each interconnection, special consideration of demand-side frequency responsive programs in ERCOT, and a reliability margin to account for the variability of frequency due to items such as time error correction, variability of load, variability of interchange, variability of frequency over the course of a normal day, and other uncertainties. The proposed margin was analyzed using a probabilistic approach based on 1-minute frequency performance data for each interconnection. The Transmission Issues Subcommittee recommended the following IFROs for the four interconnections: Eastern – -1,875 MW/0.1 Hz, Western – -637 MW/0.1 Hz, Texas – -327 MW/0.1 Hz, and Québec – -113 MW/0.1 Hz. The Transmission Issues Subcommittee IFRO report was approved by the NERC Planning Committee in September 2011 and forwarded to the Standard Drafting Team for their consideration.

A similar report had been prepared by the Resources Subcommittee of the NERC Operating Committee in January 2011, *NERC Resources Subcommittee Position Paper on Frequency Response*.[13] That report used similar Resource Contingency Protection Criteria, but used the prevalent 59.5 Hz highest UFLS setpoint for the Eastern Interconnection and a lower 59.3 Hz UFLS setpoint for ERCOT. The Resources Subcommittee analysis also used a 25% reliability margin for all four interconnections. The Resources Subcommittee recommended the following IFROs for the four interconnections: Eastern – -1,406MW/0.1 Hz, Western – -685 MW/0.1 Hz, Texas – -286 MW/0.1 Hz, and Québec – -141 MW/0.1 Hz. The Resources Subcommittee position paper was approved by the Operating Committee in March 2011 and was considered by the Frequency Response Standard Drafting Team. NERC has been tracking the decline of Frequency Response in the Eastern Interconnection for several years.

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11 The Transmission Issues Subcommittee is now the System Analysis and Modeling Subcommittee (SAMS).

12 Available here: http://www.nerc.com/docs/pc/tis/Agenda_Item_5.d_Draft_TIS_IFRO_Criteria%20Rev_Final.pdf.

13 Available here: http://www.nerc.com/docs/oc/rs/NERC%20RS%20Position%20Paper%20on%20Frequency%20Response%20Final%20(May%2027%202011).pdf.

Figure 8: Eastern Interconnection Mean Primary Frequency Response[14]
(March 30, 2012)

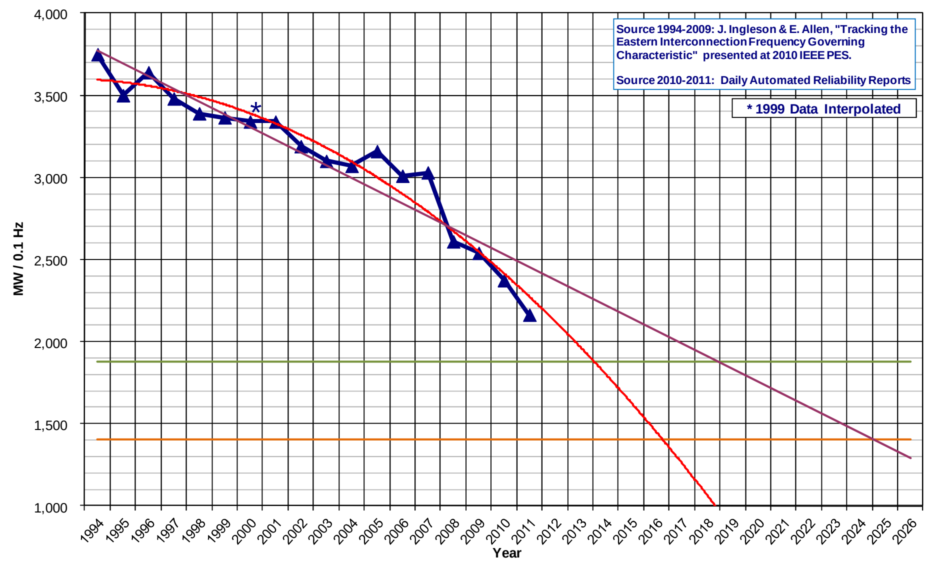


Figure 8 shows how Frequency Response has declined since 1994, as filed in NERC's *Motion for an Extension of Time of the North American Electric Reliability Corporation* (for the development of Standard BAL-003 – Frequency Response).[15] That request for extension of time was granted by the FERC in its Order on Motion for an Extension of Time and Setting Compliance Schedule (Issued May 4, 2012).[16]

Comparing the proposed IFROs from those two studies, the Eastern Interconnection IFROs range from about 1,400 MW/0.1 Hz to about 1,900 MW/0.1 Hz, the linear projection of the Frequency Response decline intercepts those target IFROs between 2019 and 2024. Even the more pessimistic polynomial projection of the decline intercepts the proposed IFROs between 2014 and 2016. This shows that there was still some time as of that filing for revising BAL-003 and responding to the decline in Frequency Response.

Figure H1 was revised shortly after the March 2012 filing in conjunction with revised Frequency Response calculation methods used in the NERC *2012 State of Reliability* report (May 2012). Figure 9 reflects the revised Frequency Response calculations for 2009 through 2011.

14 The Frequency Response data from 1994 through 2009 displayed in Figure 2 is from a report by J. Ingleson & E. Allen, Tracking the Eastern Interconnection Frequency Governing Characteristic presented at the 2010 IEEE

15 Filing available at:

16 Order available at:

Figure 9: Updated Eastern Interconnection Mean Primary Frequency Response (May 2012)

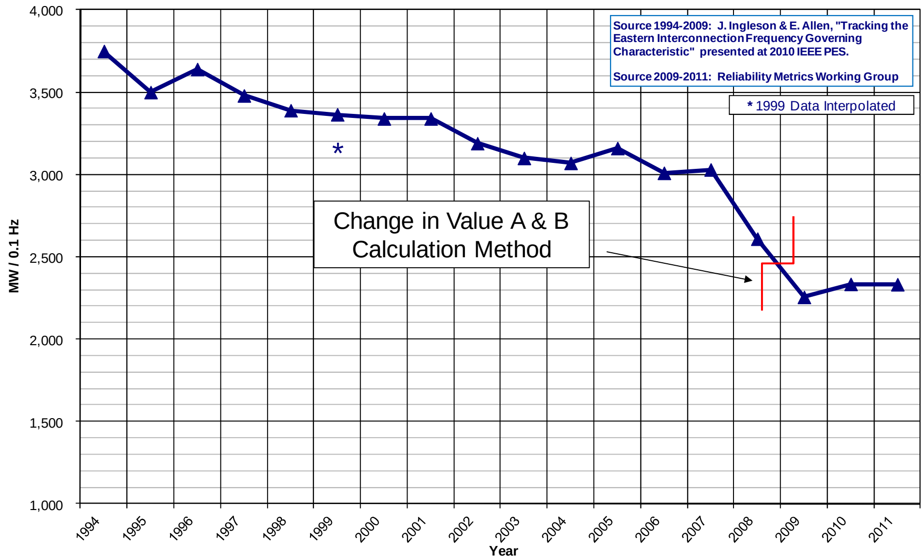


Figure 9 shows an improvement in Frequency Response in 2009 through 2011 due to alignment of the methods for calculation Values A and B. That method is consistent with the method being proposed in Standard BAL-003. The method has since been further refined, as reflected in the Statistical Analysis of Frequency Response section of this report.

Figures 10 through 14 show the statistical analysis of the Frequency Response for 2009 through 2011 for the Eastern, Western, and ERCOT Interconnections from the *2012 State of Reliability* report in box plot format (only 2011 data was available for the Québec Interconnection).

Figure 10: Eastern Interconnection Frequency Response Analysis for 2009 to 2011

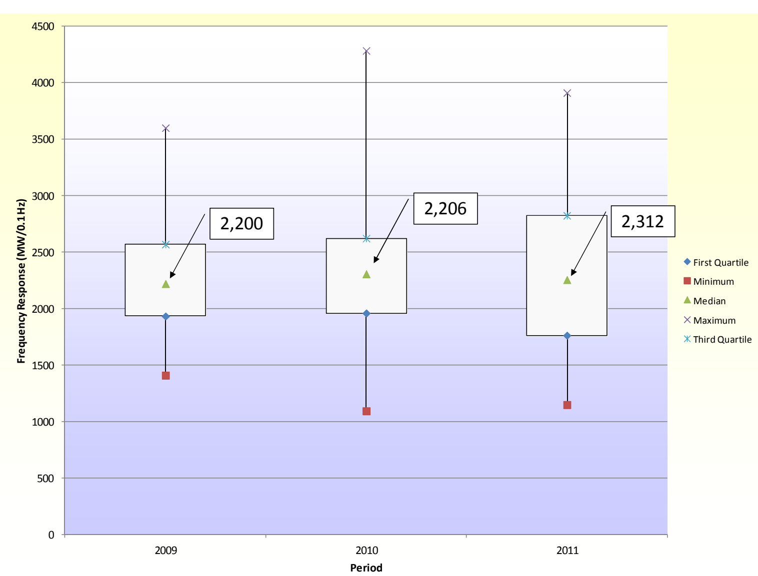


Figure 11: Western Interconnection Frequency Response Analysis for 2009 to 2011

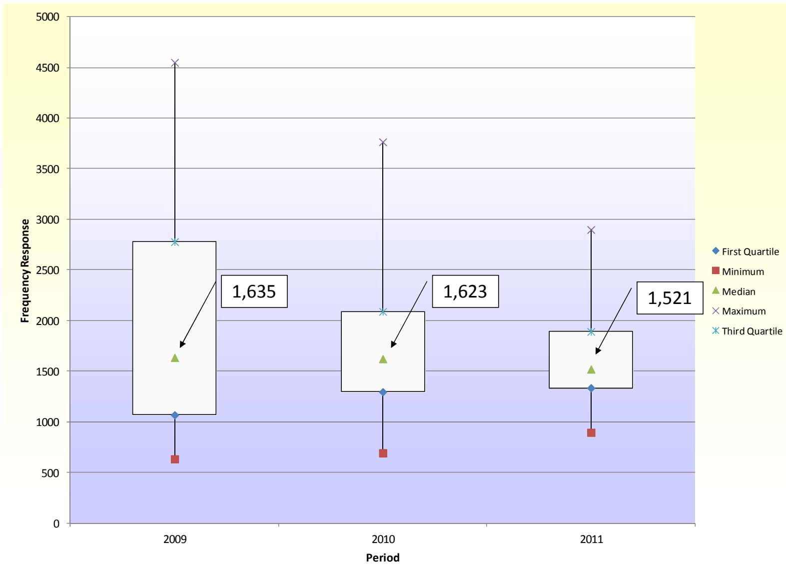
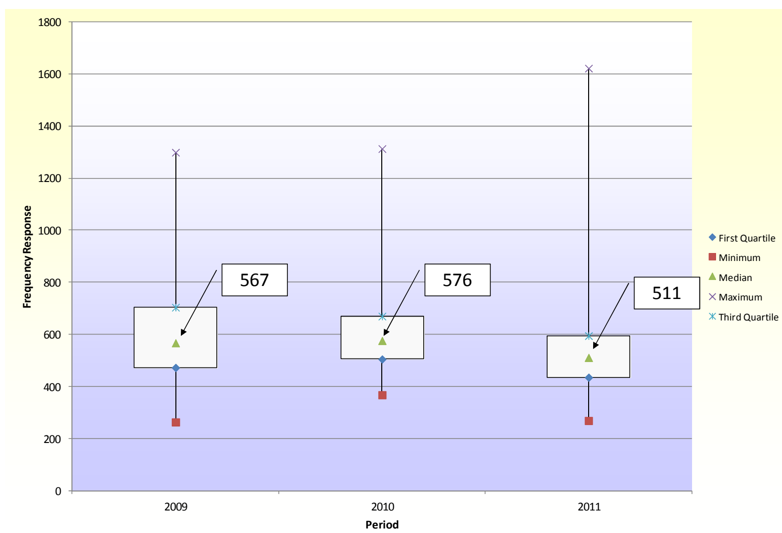
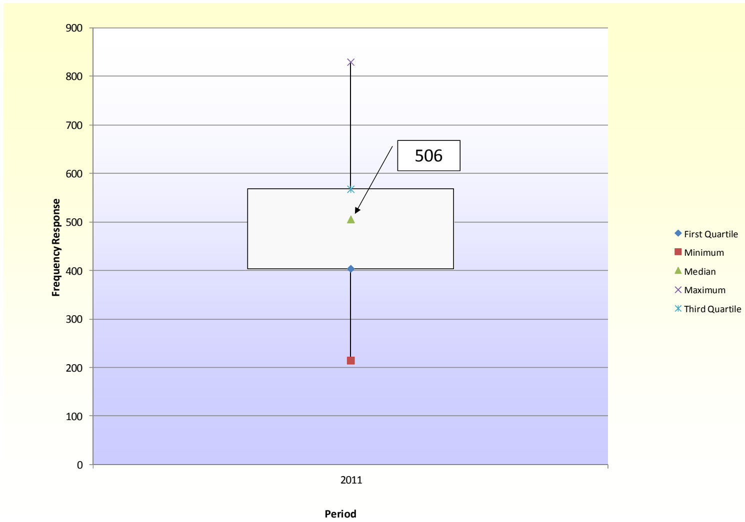


Figure 13: ERCOT Interconnection Frequency Response Analysis for 2009 to 2011



It is important to note the range of variability of the Frequency Response for each year. Additional events and modifications to the calculation methods for the A, B, and C values have been since these values were calculated for the May 2012 report. The new values are reflected in the Statistical

Figure 14: Québec Interconnection Frequency Response Analysis for 2011



Statistical Analysis of Frequency Response (Eastern Interconnection)

In July 2012, a statistical analysis of the Frequency Response of the Eastern Interconnection was performed for the calendar years 2009-2011 and the first three months of 2012. The size of the dataset was 163 (with 44 observations for the year of 2009, 49 for 2010, 65 for 2011, and 5 for 2012).

Table 1: Statistical Analysis Dataset

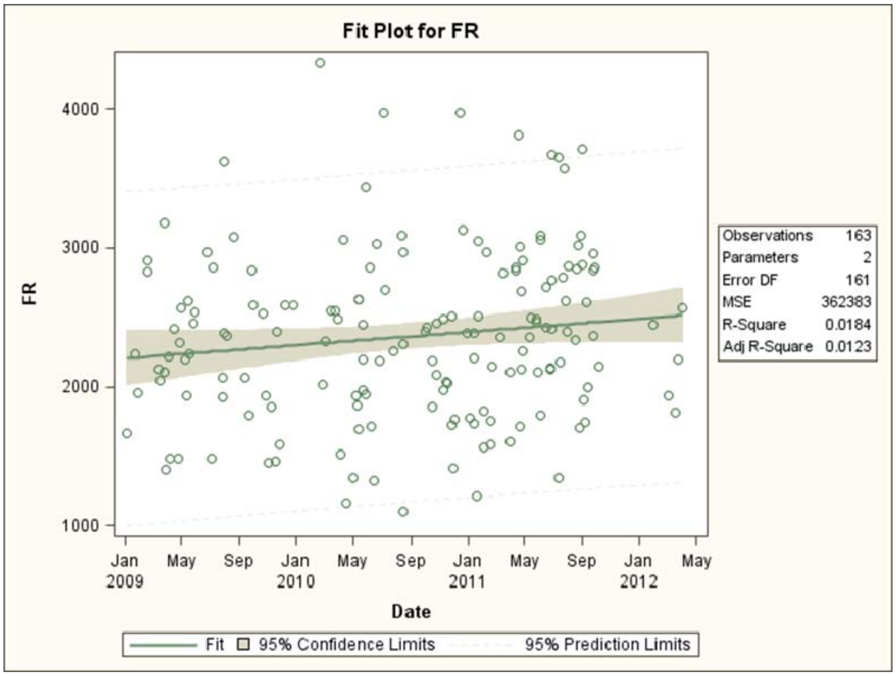
Sample Parameter	2009	2010	2011
Sample Size	44	49	65
Sample Mean	2,258.4	2,335.7	2,467.8
Sample Standard Deviation	522.5	697.6	593.7

The report on that analysis is contained in Appendix G and its results are paraphrased here for brevity. For this analysis, Frequency Response pertains to the absolute value of Frequency Response.

Key Statistical Findings

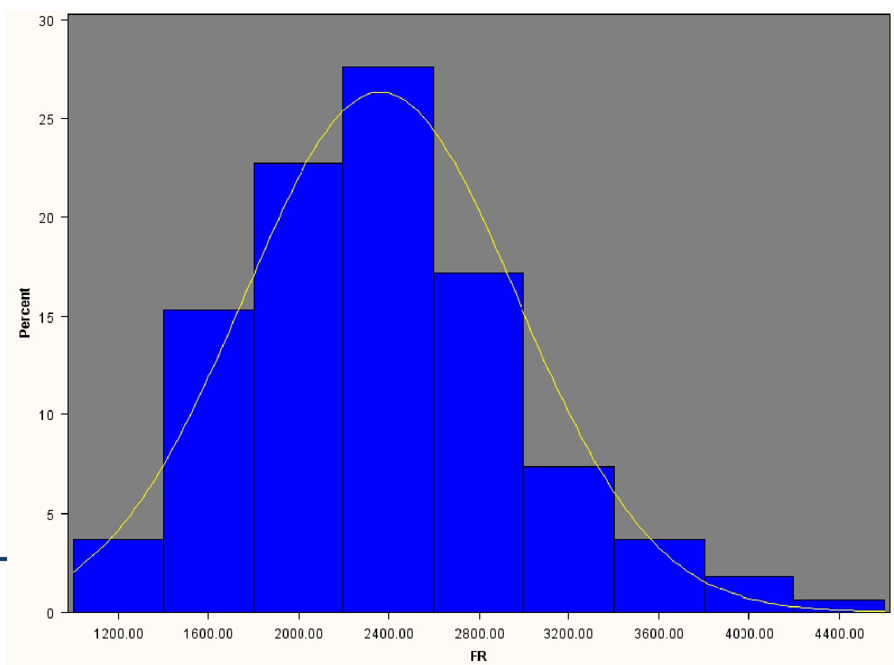
1. A linear regression equation with the parameters defined in the Appendix G is an adequate statistical model to describe a relationship between time (predictor) and Frequency Response (responsive variable). The graph of the linear regression line and Frequency Response scatter plot is given in Figure 15.

Figure 15: Linear Regression Fit Plot for Eastern Interconnection Frequency Response



2. The probability distribution of the whole Frequency Response dataset is approximately normal, with the expected Frequency Response of 2,363 MW/0.1 Hz and the standard deviation of 605.7 MW/0.1 Hz as shown in Figure 14.
3. The comparative statistical analysis for every pair of years shows that the changes in the 2010 data versus the 2009 data (and in the 2011 data versus the 2010 data) are not statistically significant to lead to the conclusion that the mean value of Frequency Response for any two consecutive years changes. However, the data for 2009 and 2011 differ at the level that results in an acceptance of the hypothesis that the expected value of Frequency Response for 2011 is higher than for 2009.

Figure 16: Probability Distribution Eastern Interconnection Frequency Response

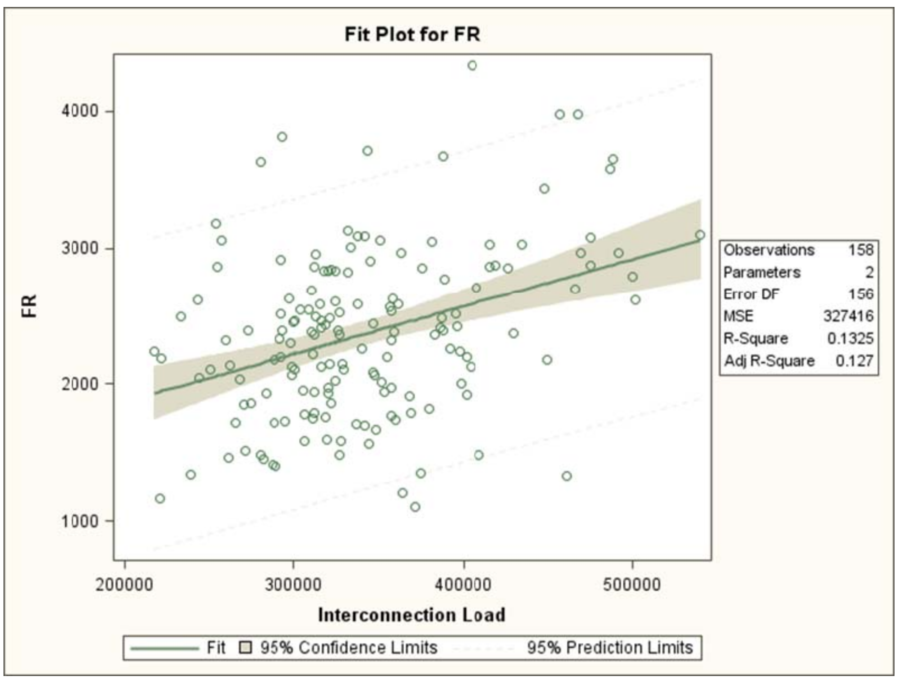


2009 through April 2012

4. There is a statistically significant seasonal (Summer/Not summer) correlation to the variability of Frequency Response for the Eastern Interconnection. The expected (mean of the sample) Frequency Response for summer (June-August) frequency events is 2,598MW/0.1 Hz versus 2,271 MW/0.1 Hz for non-summer events. This is attributable to at least two factors: higher load contribution to frequency response and increased generation dispatch of units that have higher Frequency Response characteristics.

5. Pre-disturbance (average) frequency (Value A) is another statically significant contributor to the variability of Frequency Response. The expected (mean of the sample) Frequency Response for events where Value A is greater than 60 Hz is 2,188 MW/0.1 Hz versus 2,513 MW/0.1 Hz for events where Value A is less than or equal to 60 Hz.

Figure 17: Linear Regression for Frequency Response and Interconnection Load



6. The difference in average Frequency Response between On-Peak events and Off-Peak events is not statistically significant and could occur by chance. According the NERC definition, for Eastern Interconnection On-Peak hours are designated as follows: Monday to Saturday hours from 07:00 to 22:00 (Central Time) excluding six holidays: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. Analysis showed that the On-Peak/Off-Peak variable is not a statistically significant contributor to the variability of Frequency Response. There is a positive correlation of 0.06 between the indicator function of On-Peak hours and Frequency Response; however, difference in average Frequency Response between On-Peak events and Off-Peak events is not statistically significant and could occur by chance (P-value is 0.49).

7. There is a strong positive correlation of 0.364 between Interconnection Load and Frequency Response for the 2009-2011 events. On average, when Interconnection Load changes by 1,000 MW, Frequency Response changes by 3.5 MW/0.1Hz.

   This correlation indicates a statistically significant linear relationship between Interconnection Load (predictor) and Frequency Response (response variable). Figure Stat3 shows the linear regression line and Frequency Response scatter plot. For the dataset, the regression line has a positive slope estimate of 0.00349; thus, the Frequency Response variable increases when Interconnection Load grows.

8. For the 2009-2011 dataset, five variables (Time, Summer, High pre-disturbance frequency, On-Peak/Off Peak hour, and Interconnection Load) have been involved in the statistical analysis of Frequency Response. Four of these, Time, Summer, On-Peak hours, and Interconnection Load have a positive correlation with Frequency Response (0.16, 0.24, 0.06, and 0.36, respectively), and the high pre-disturbance frequency has a negative correlation with Frequency Response (-0.26). The corresponding coefficients of determination R^2 are 2.6%, 5.8%, 0.4%, 13.3% and 6.9%. These values indicate that about 2.6% in variability of Frequency Response can be explained by the changes in time, about 5.8% of frequency response variability is seasonal, 0.4% is due to On-Peak/Off-Peak changes, 13.3% is the effect of the Interconnection Load variability, and about 6.9% can be accounted for by a high pre-disturbance frequency. However, the correlation between Frequency Response and On-peak hours is not statistically significant and with the probability about 0.44 occurred by mere chance (the same holds true for the corresponding R^2).

   Therefore, out of the five parameters, Interconnection Load has the biggest impact on Frequency Response followed by the indicator of high pre-disturbance frequency. A multivariate regression with Interconnection Load and starting frequency (Value A) greater than 60 Hz as the explanatory variables for Frequency Response yields a linear model with the best fit (it has the smallest mean square error among the linear models with any other set of explanatory variables selected from the five studied). Together these two factors can account for about 20% in variability of Frequency Response.

Table 2: Explanatory Variables for Eastern Interconnection Frequency Response

Variable X	Sample Correlation (X, FR)	P-Value	Linear Regression Statistically Significant	Coefficient of Determination R^2 (Single Regression)
Interconnection Load	0.36	<0.0001	Yes	13.3%
Value A > 60 Hz	-0.26	0.0008	Yes	6.9%
Summer/Not Summer	0.24	0.0023	Yes	5.8%

Table 2: Explanatory Variables for Eastern Interconnection Frequency Response				
Variable X	Sample Correlation (X, FR)	P-Value	Linear Regression Statistically Significant	Coefficient of Determination R^2 (Single Regression)
Date	0.16	0.044	Yes	2.6%
On-Peak Hours	0.06	0.438	No	N/A

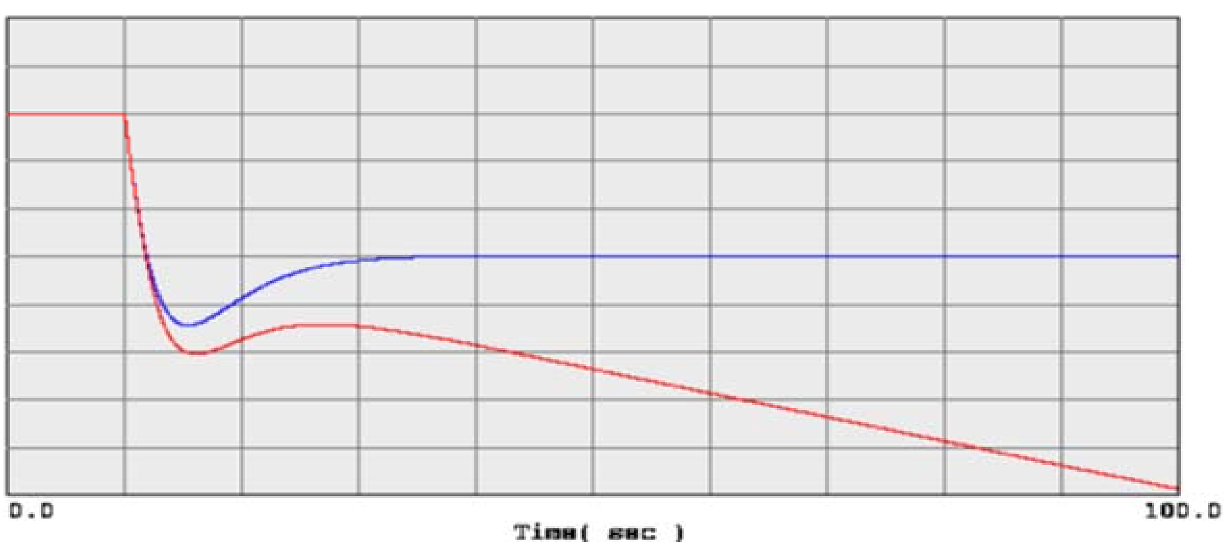
Therefore, there are other parameters that affect Frequency Response, have a low correlation with those studied, together account for a remaining share in Frequency Response variability, and minimize a random error variance.

Note that Interconnection Load is positively correlated with Summer (0.55), On-Peak hours (0.45), and Date (0.20) but uncorrelated with starting frequency greater than 60 Hz (P-value of the test on zero correlation is 0.90).

Frequency Response Withdrawal

Withdrawal of Primary Frequency Response is an undesirable characteristic associated most often with digital turbine-generator control systems using set-point output targets for generator output. These are typically outer-loop control systems that defeat the Primary Frequency Response of the governors after a short time to return the unit to operating at a requested MW output.

Figure 18: Primary Response Sustainability



Blue = frequency response is sustained
Red = generator has a "slow" load controller returning to MW set-point

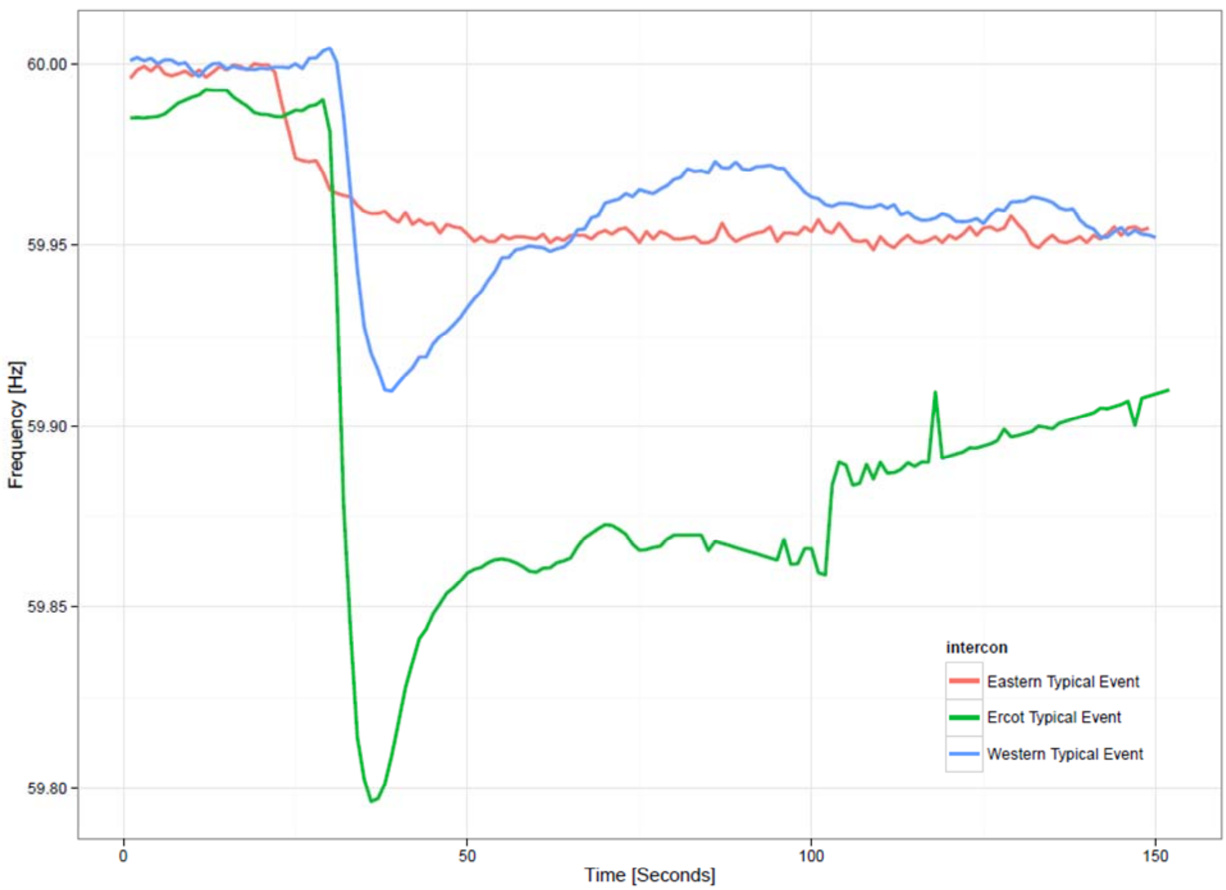
Figure 18 shows how the outer loop control on a single machine would influence

Some of the typical causes of the withdrawal are:

- Plant outer-loop control systems – driving the units to MW set points
- Unit characteristics
  - Plant incapable of sustaining Primary Frequency Response
  - Governor controls overridden by other turbine/steam cycle controls
- Operating philosophies – operating characteristic choices made by plant operators
  - Desire to maintain highest efficiencies for the plant

The phenomenon is most prevalent in the Eastern Interconnection and can be easily be seen in the comparison of the typical frequency response performance of the three interconnections (Figure SS).

Figure 19: Typical Interconnection Responses for 2011



Sustainability of Primary Frequency Response becomes more important during light-load conditions (nighttime) when there are generally fewer frequency-responsive generators on line.

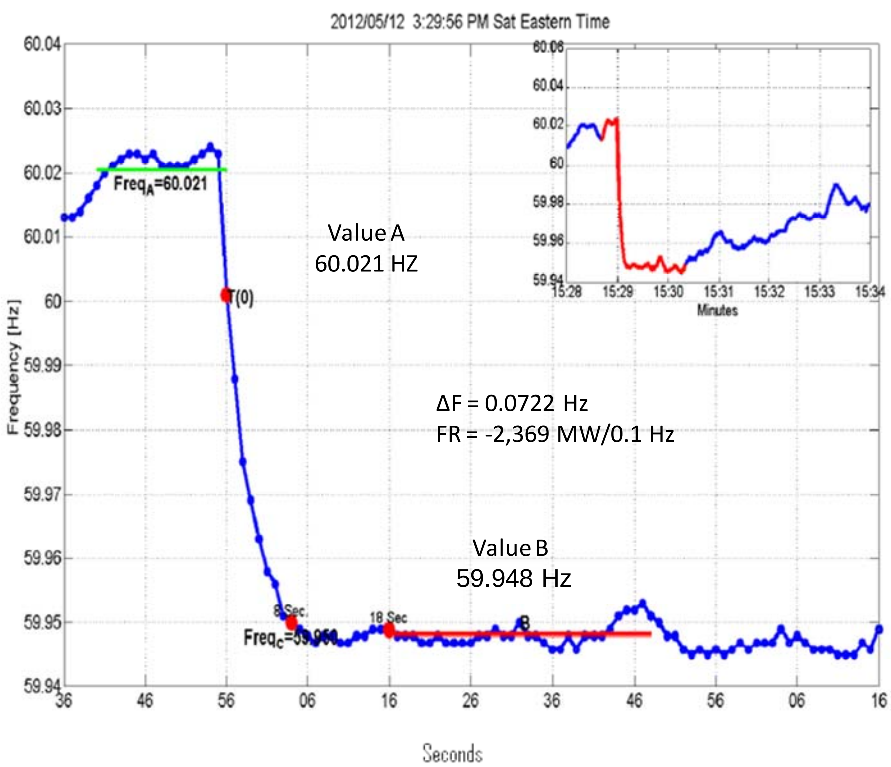
A number of the governor survey questions addressed the operational status and parameters of the governor fleet. The results of the survey show:

- About 90% of the generators were reported to have governors.
- Virtually all (95% to 99%by interconnection) of the GOs and GOPs reported that their governors are operational.
- From 80% to 85% (by interconnection) of the governors were reported to be capable of sustaining primary frequency response for longer than 1 minute if the frequency remained outside of their deadband.
- Roughly 50% of the governors reported that they had unit-level or plant-level control systems that override or limit governor performance.

Therefore, despite the fact that the majority of generators reported that they have operational, half of them have unit- or plant-level control systems that override governor responses to frequency deviations to return the units to scheduled output (MW setpoint) or an optimized operating point for economic reasons. These factors heavily influence the sustainability of primary Frequency Response, contributing to the withdrawal symptom often observed. This is often evident during light load periods in the middle of the night when high-efficiency, low-cost units that operate on MW setpoints are the majority of the generators dispatched to serve load.

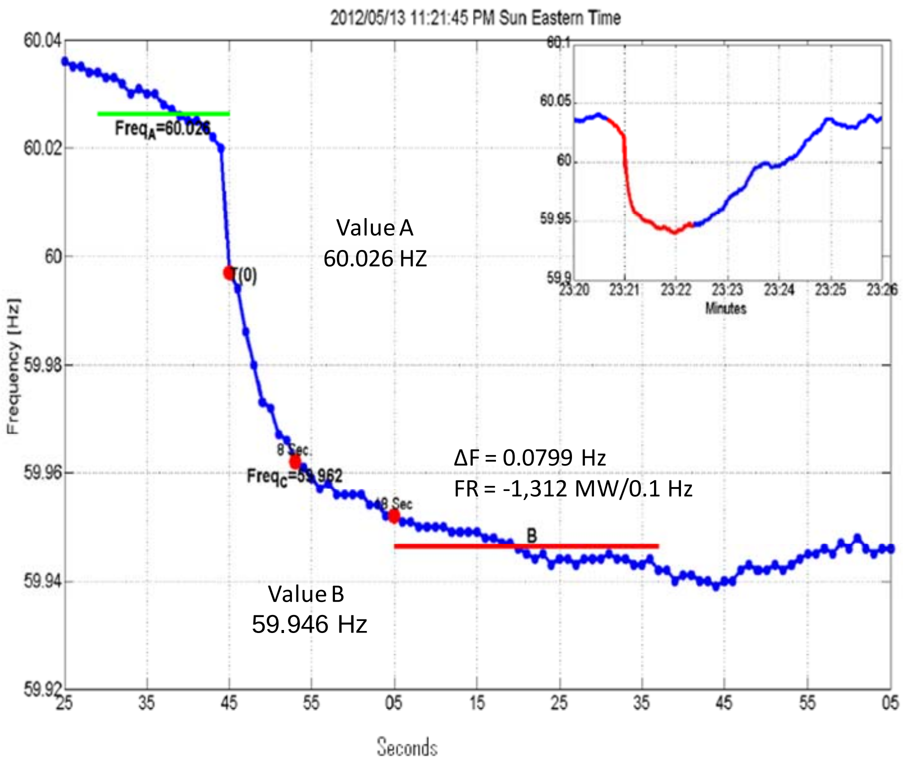
This was exhibited by two events involving generator trips in the spring of 2012 in one weekend. During the first event (Figure 20), 1,711 MW of generation was tripped with a typical -2,369 MW/0.1 Hz Frequency Response.

Figure 20: 3:30 pm Saturday Afternoon 1,711 MW Resource Loss



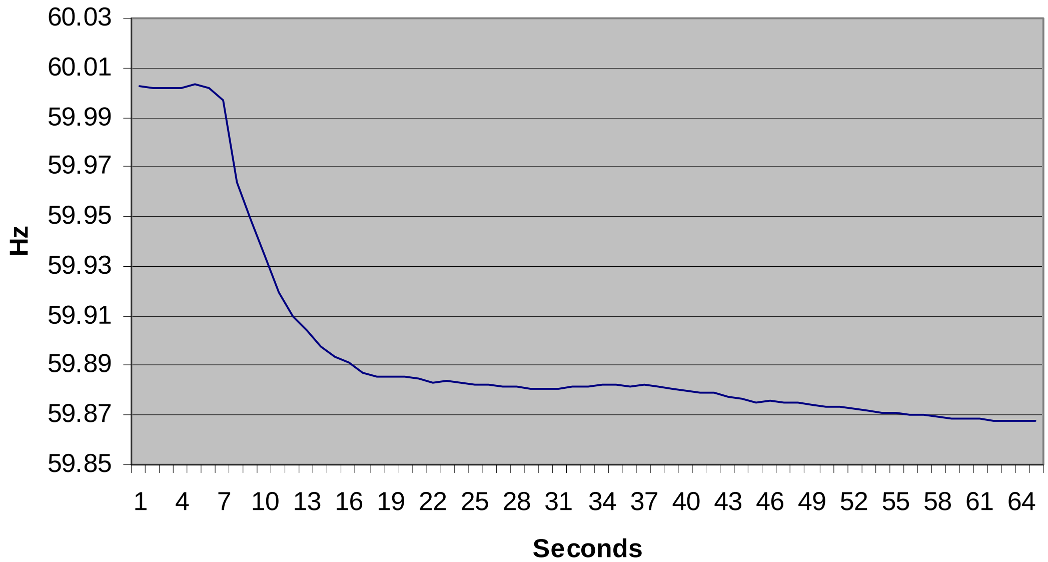
The second event occurred late Sunday night when load in the Easter Interconnection was much lighter, and the generators dispatched, probably the most efficient units, were of a different character. Despite the resource loss being almost 700 MW less, the Frequency Response of the interconnection was significantly reduced, and exhibited the “lazy L” of Primary Frequency Response withdrawal. Point C (the nadir) defined to occur during the first 8 seconds (at that time) was 59.962 Hz, while a lower point of about 59.939 Hz occurred about 1 minute after the event.

Figure 21: 11:21 pm Sunday Night 1,049 MW Resource Loss



These two events point to the composition of the dispatch and the characteristics of the units on line as primary elements in the Frequency Response strength, as well as the key elements in creating withdrawal. Therefore, when calculating an interconnection frequency response obligation (IFRO), it is important for operational planners and operators to recognize the potential for that withdrawal and the frequency consequentially being lower 1-2 minutes after the beginning of the event.

Figure 22: Interconnection Frequency – August 4, 2007 EI Frequency Excursion



A similar withdrawal was experienced during the major frequency excursion of August 4, 2007. During that event some 4,500 MW of generation was lost

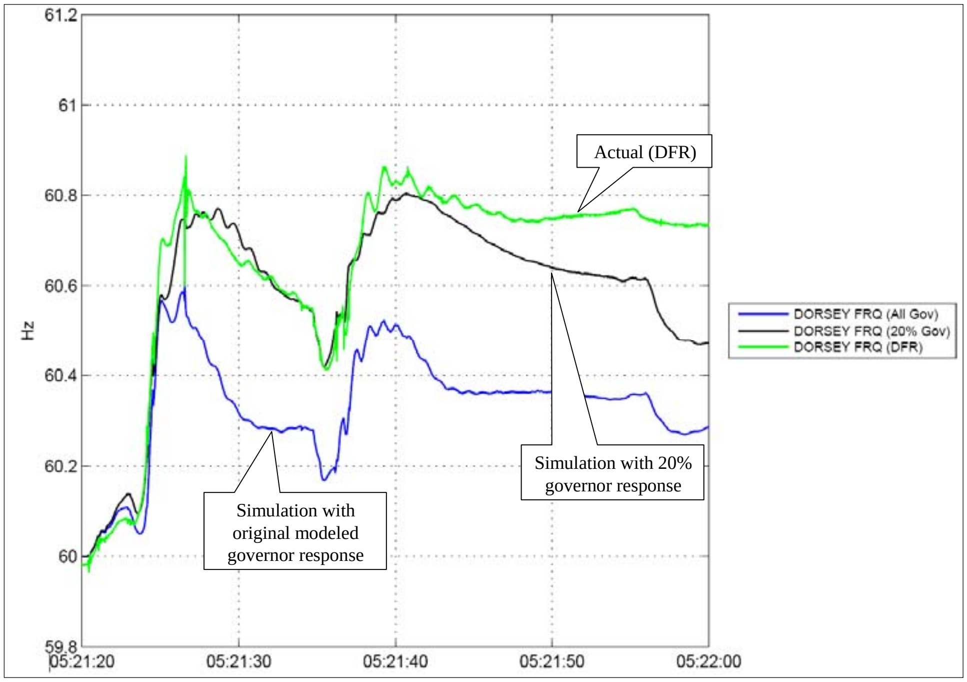
The lowest frequency in the event was about 59.868 Hz some 60+ seconds after the start. Recovery to pre-event frequency was about 8 minutes, but the measurement of Value B (20 to 52 seconds) would not capture the lowest frequency. It is important that that phenomenon be recorded and trended to determine if it is improving or deteriorating.

Recommendation – Measure and track trends Frequency Response sustainability by observing frequency between T+45 seconds and T+180 seconds. A pair of indices for gauging sustainability should be calculated comparing that value to both the Point C and Value B.

Modeling of Frequency Response in the Eastern Interconnection

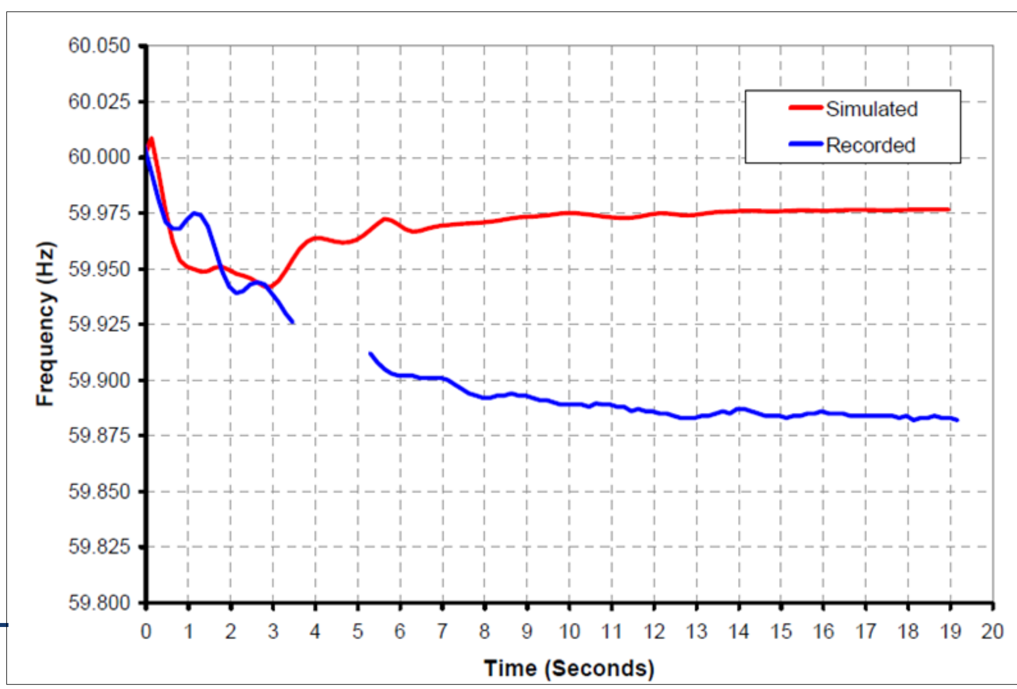
Modeling of frequency response characteristics has been a known problem since at least 2008, when forensic modeling of the Eastern Interconnection required a “de-tuning” of the existing MMWG dynamics governor to 20 % of modeled (80% error) to approach the measured frequency response values from the event. Figure 23 shows the response comparison for that event analysis.

Figure 23: 2007 Event Frequency Response Forensic Analysis



Although the event was an over-frequency problem at that point, it is indicative of the larger problem of governor modeling in the Eastern Interconnection. The problem was further highlighted in the 2010 “Use of Frequency Response Metrics to Assess the Planning and Operating Requirements for Reliable Integration of Variable Renewable Generation,” by Ernest Orlando Lawrence Berkeley National Laboratory (LBNL). In that analysis, an attempt was made to simulate a 4,500 MW loss event that occurred on August 4, 2007. Figure 24 shows a comparison of the simulation to the measured frequency from the event.

Figure 24: Eastern Interconnection Frequency Response – August 4, 2007
Initial 20 Seconds



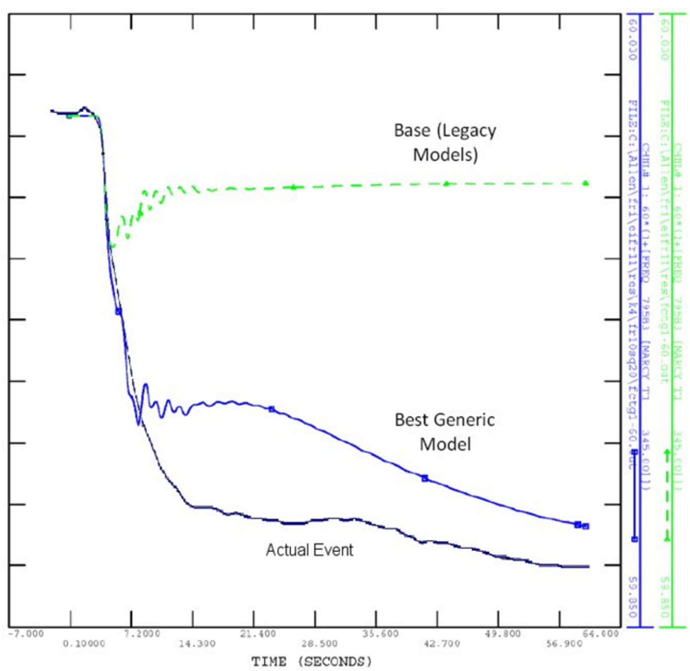
As part of the NERC Frequency Response Initiative and the Modeling Improvements Initiative, NERC collaborated with the Eastern Interconnection Reliability Assessment Group (ERAG) Multiregional Modeling Working Group (MMWG) performed an analysis of the modeling of overall frequency response in the Eastern Interconnection. That review was a prelude to a plan for a thorough examination of the governor models in the Eastern Interconnection dynamics study cases that are assembled by the MMWG. That report concluded that: “The turbine-governor modeling currently reflected in the MMWG dynamics simulation database is not a valid representation of the frequency control behavior of the Eastern Interconnection.”

That project created a “generic case” dynamics model, replacing the turbine governor models in the case with a generic governor model in order to ascertain the basic characteristics of the frequency response of the Eastern Interconnection. Figure 25 shows a comparison of the actual event data, and the simulations using the original governor data and the generic case.

The characteristic found in that study were:

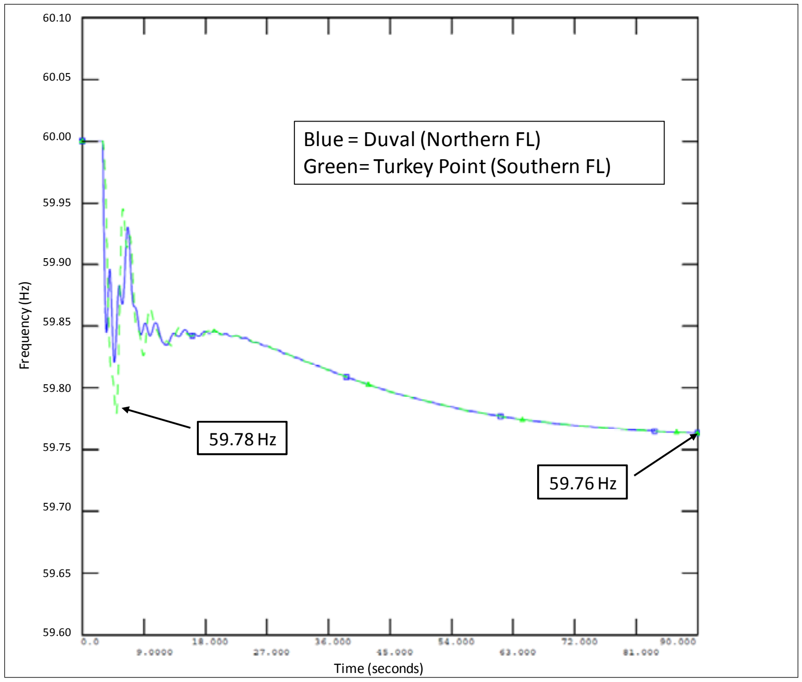
- Only 30 % of the units on line provide primary frequency response
- 2/3 of the units that did respond exhibit withdrawal of primary frequency response
- Only 10 % of units on line sustain primary frequency response

Figure 25: Comparison of Legacy and Generic Simulations to August 4 Event



Following that study, a follow-on analysis was performed by NERC staff to determine the general order of magnitude of a frequency event that could be sustained by the Eastern Interconnection without violating the 59.7 Hz first step UFLS in FRCC. A simulation was run tripping about 8,500 MW of generation in the southeast United States (north of Florida). Figure 26 shows the result of that testing.

Figure 26: 8,500 MW Resource Loss Simulation



The simulation showed that the lowest frequency would be about 59.76 Hz in southern Florida. The initial nadir of 59.78 Hz in southern Florida is lower than the nadir in northern Florida due to the wave properties of the disturbance.

Although the simulations using the generic governor models are not exact, that analysis is indicative that the Eastern Interconnection can sustain a resource loss event significantly higher than the Resource Contingency Protection Criteria proposed in this report.

Concerns for Future of Frequency Response

There is a growing concern about the future of Frequency Response in light of a number of factors:

- **Electronically-coupled resources** – The incorporation of renewable resources such as wind and solar and the increasing penetration of variable speed motor drives present a continuing erosion of system inertia; all are electronically coupled to the system. As such, those resources, unless specifically designed to mimic inertial response, do not have inertial response.

- **Electronically-coupled loads** – As synchronous motors are replaced by variable speed drives, the load response of the motors is eliminated by the power electronics of the motor controller. This reduces the load damping factor for the interconnection.

- **Displacement of traditional turbine-generators in the dispatch** – Traditional turbine-generators are being displaced in the dispatch, particularly during off-peak hours when wind generation is at its highest and the loads and generation levels are at their lowest. Such displacement of frequency responsive resources increasingly depletes the inertia of the interconnection at those times.

Role of Inertia in Frequency Response

Inertia plays a crucial role in determining the slope of a frequency decline during a resource loss event.

The slope of frequency excursion is determined by the inertia of the system and a factor to account for the load damping characteristics of the interconnection.

$$Slope = \frac{\Delta Power}{D + 2H}$$

Where:

D = Load Damping Factor

The load damping factor ranges from 0 to 2, where 2 would represent a load of all motors.

H = Inertia Constant of the interconnection

The inertia constant ranges from 2.5 to 6.5

Figure 27 shows the sensitivity of Frequency Response to changes to system inertia. The lower green curve represents an inertia constant of 2.5 and the lower red curve represents an inertia constant of 5.0.

Figure 27: Frequency Response Sensitivity to System Inertia

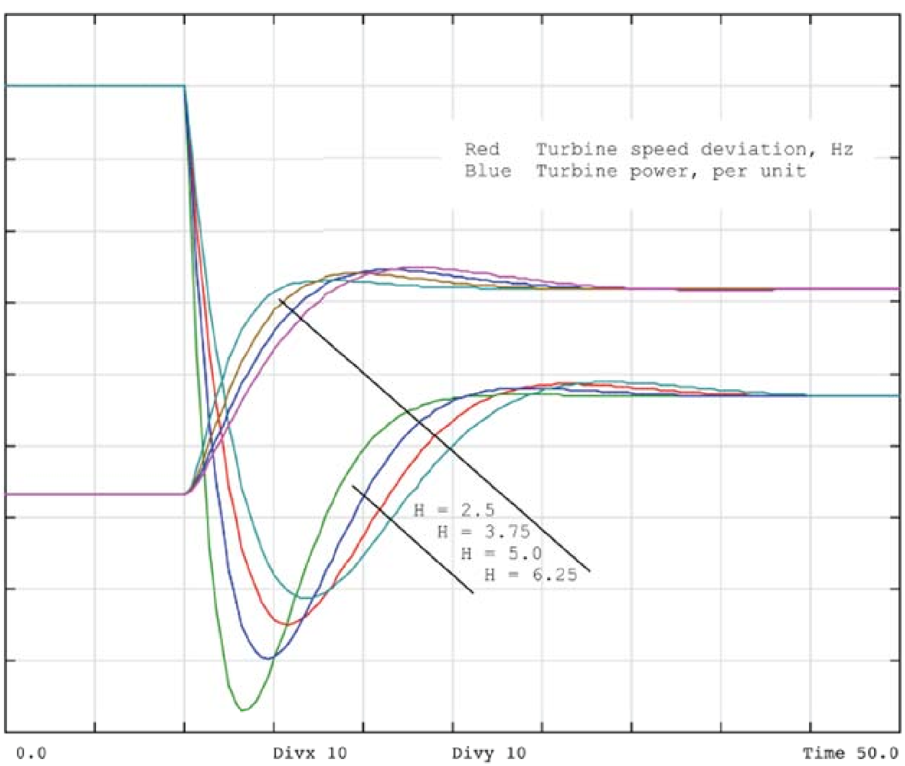
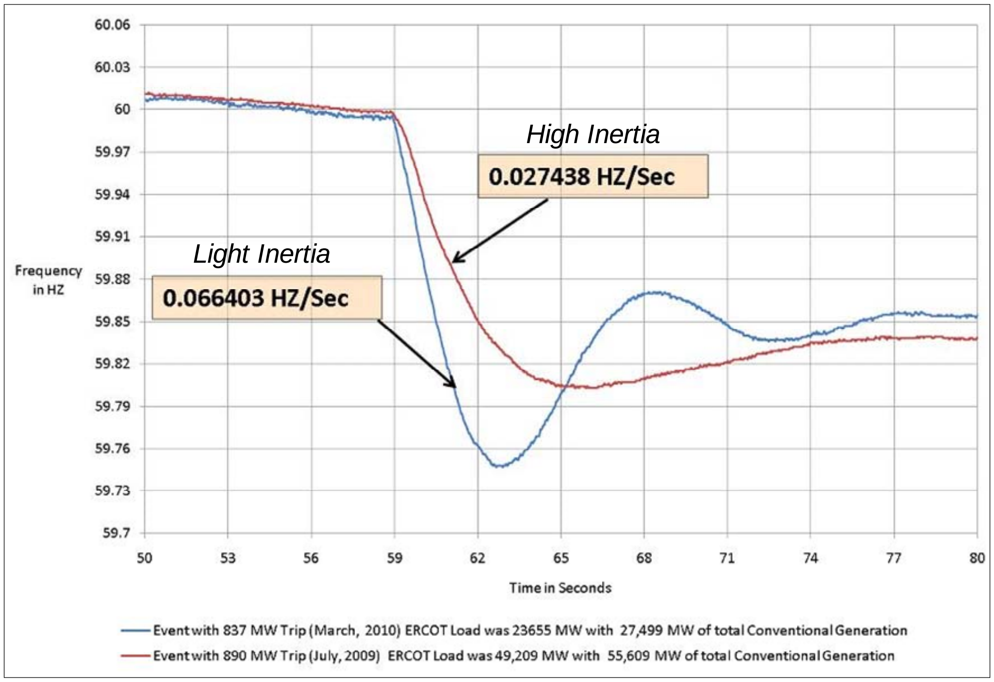


Figure 28 shows an actual example form ERCOT of how Frequency Response is changed for similarly-sized resource loses with differences in inertia. It is clear that when the inertia on the system is lower, a similar resource MW loss creates a much steeper and deeper frequency excursion. This is a good example of the displacement of traditional resources with electronically-coupled during light-load periods.

Figure 28: Inertial Response Sensitivity



Need for Higher Speed Primary Frequency Response

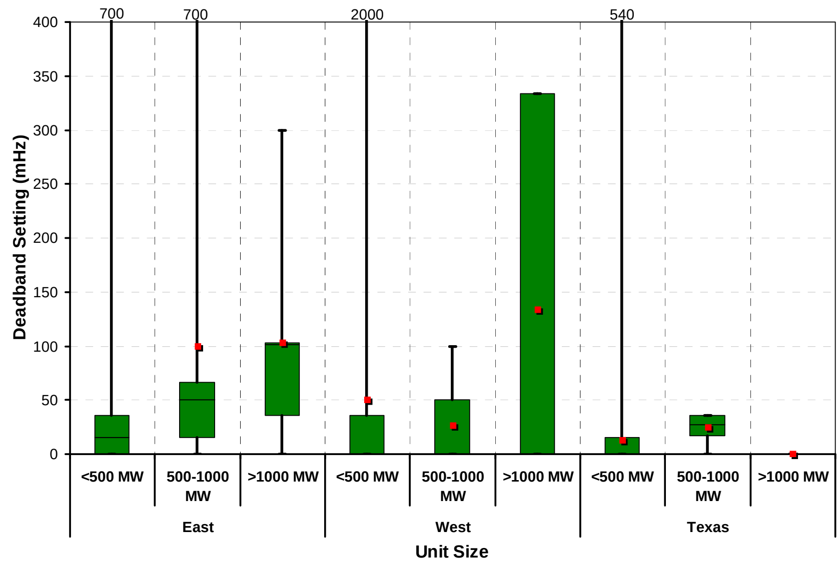
A major for the reduction of inertia is that it drives a need for higher-speed response to frequency excursions. If the slope of the frequency decline is steeper, it is necessary for high-speed injection of energy to arrest the decline in order to prevent the excursion from being too deep. Such energy injection can come from a number of sources such as energy storage devices and wind turbines with modified inverters.

Preservation or Improvement of Existing Generation Primary Frequency Response

Additionally, to further help ensure strong overall frequency response, it is important to preserve or improve the primary frequency response of the existing generation fleet. The Role of Governors section of this report discusses the results of the 2010 survey on generator governors. The survey results show that there is a significant portion of the existing generator fleet that has operational governors. However, the reported deadband ranges make those governors ineffective for all but catastrophic losses of resources; the deadband settings. Figure 29 shows the reported deadband ranges.

If the existing generator fleet Primary Frequency Response performance can be improved through adjustments in deadbands and implementation of no-step droop responses, a significant improvement in interconnection frequency response could be realized. Further, if all of the existing generators are made capable of response, any generators that are on line during light-load periods would be more able to provide response.

Figure 29: Reported Governor Deadband Settings



The Role of Governors section of this report recommends immediate development of a NERC turbine-generator governor Guideline calling for deadbands of ±16.67 mHz with droop settings of 4%-5% depending on turbine type in order to retain or regain frequency response capabilities of the existing generator fleet.

Interconnection Frequency Response Obligation (IFRO)

Tenets of IFRO

The IFRO is intended to be the minimum amount that Frequency Response that must be maintained by the interconnection. A portion of the IFRO should be allocated to each of the Balancing Authorities (BAs) in the interconnection representing their minimum responsibility. Balancing Authorities that may be susceptible to islanding may need to carry additional frequency responsive reserves to coordinate with their under-frequency load shedding (UFLS) plans for islanded operation in order to be sustainable.

A number of methods to assign the frequency response targets for each interconnection can be considered. Initially, the following tenets should be applied:

1. A frequency event should not trip the first stage of regionally approved under-frequency load shedding (UFLS) systems within the interconnection.
2. Local tripping of first-stage UFLS systems for severe frequency excursions, particularly those associated with protracted faults or on system on the edge-of the interconnection, may be unavoidable.
3. Other frequency-sensitive loads or electronically-coupled resources may trip during such frequency events (as is the case for photovoltaic inverters in the Western Interconnection).
4. Other susceptible frequency-sensitivities may have to be considered in the future (electronically coupled load common-mode sensitivities).

UFLS is intended to be a safety net to prevent against system collapse from severe contingencies. Conceptually, that safety net should not be violated for frequency events that happen on a relatively regular basis. As such, the criteria for resource events for which frequency response should be adequate to avoid violating UFLS settings approved by the Regional Entities.

The Frequency Response Standard Drafting Team (FRRSDT) is proposing an administered value approach for the BAL-003 Field Trial. Eventually, an agreed upon method of determining the Interconnection FRO will be included in a Reliability Standard, or in the Rules of Procedure[17].

[17] http://www.nerc.com/files/NERC_Rules_of_Procedure_EFFECTIVE_20110412.pdf

Statistical Analyses

Frequency Variation Statistical Analysis

A statistical analysis of the variability of frequency for each of the four interconnections was performed of 1-second measured frequency for the Eastern, Western, and ERCOT Interconnections for 2007 through 2011 (5 years) was completed. Data was only available for 2010 and 2011 for the Québec Interconnection. This variability accounts for items such as time error correction, variability of load, interchange, and frequency over the course of a normal day, and other uncertainties, including time error corrections and all frequency events– no large events were excluded. The results of the analysis are shown in Table 3.

Table 3: Interconnection Frequency Variation Analysis (Hz)

Value	Eastern	Western	ERCOT	Québec
Timeframe	2007 – 2011	2007 – 2011	2007 – 2011	2010 – 2011
Number[18] of Samples	150,318,562	149,595,982	137,973,465	34,494,049
Expected Value	**60.00010166**	**59.99998909**	**60.00003953**	**60.00002303**
Maximum Value	60.3090	60.3575	62.1669	60.8776
Minimum Value	59.0015	59.6340	58.0000	59.1879
Variance of Frequency (σ^2)	0.000253348 Hz^2	0.00019094 Hz^2	0.000657831 Hz^2	0.00035315 Hz^2
σ	0.015916902	0.013818286	0.025648222	0.01879236
2σ	0.031833803	0.02763656	0.051296443	0.03758472
3σ	0.047750705	0.04145483	0.076944665	0.05637708
Starting Frequency (F_{Start}) 5% of lower tail samples	**59.973**	**59.977**	**59.961**	**59.971**

For each interconnection, the distribution of the Interconnection frequency fails the normality test (both the chi-square goodness-of-fit and the Kolmogorov-Smirnov goodness-of-fit) at any standard significance level. The combined datasets for the interconnection frequency consist of very large numbers of observations. For such large samples, the empirical distribution can be considered as a very good approximation of the actual distribution of the frequency, and was judged to be a better predictor than use of standards deviation of predicting the interconnection starting frequencies for an event. The rate of convergence in the Glivenko-Cantelli theorem is $n^{(-1/2)}$, where n is the sample size. Therefore, quantiles of the empirical distribution function can be used directly to calculate intervals where values of frequency belong with any pre-determined probability.

18 Numbers of samples vary due to exclusion of data drop-outs and other obvious observation anomalies.

Only resource losses (frequency drops) are examined for IFRO calculations; so the focus is on the one-sided lower tail of the distribution for frequencies that fall outside the upper 95% interval of the overall distribution. Therefore, the starting frequency that should be used for the calculation of the IFROs is the 10% quantile frequency value (bolded on Table FA1), which represent a 95% confidence in the prediction for that single tail.

Those starting frequencies encompass all variations in frequency, including changes to the target frequency during time error correction (TEC). That eliminates the need to expressly evaluate TEC as a variable in the IFRO calculation.

Recommendation – The Starting Frequency for the calculation of IFROs should be frequency of the 5% of lower tail samples from the statistical analysis, representing a 95% confidence that frequencies will be at or above that value at the start of any frequency event.

Figures 30 through 33 show the interconnection histograms broken into 1-mHz "bins." A complete set of graphs for the four interconnections are located in Appendix D of this report.

Figure 30: Eastern Interconnection 2007-2011 Frequency Histogram

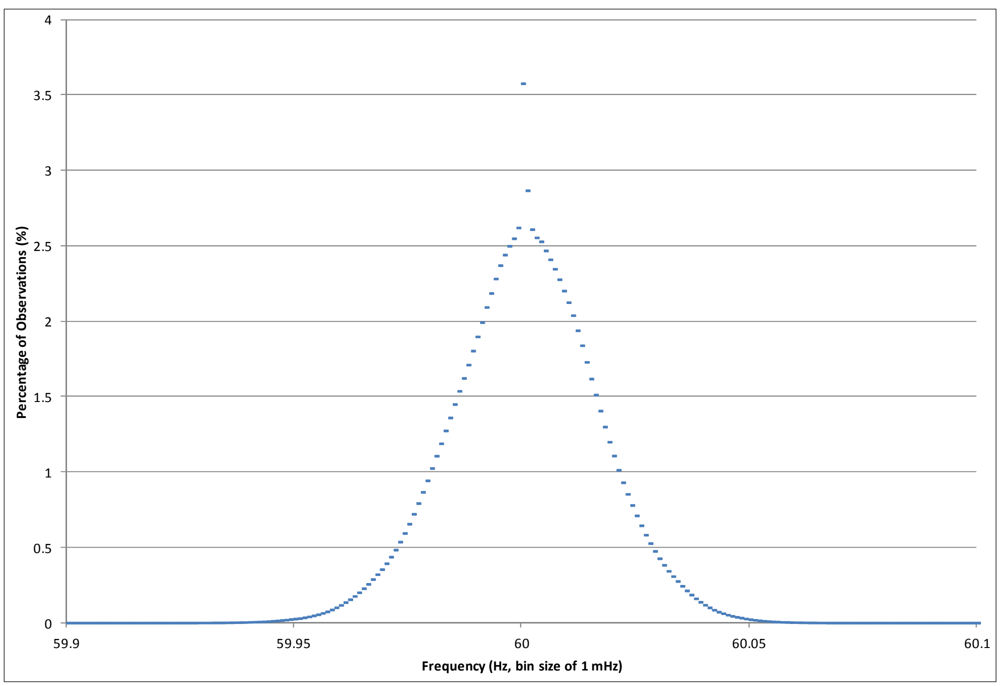


Figure 31: Western Interconnection 2007-2011 Frequency Histogram

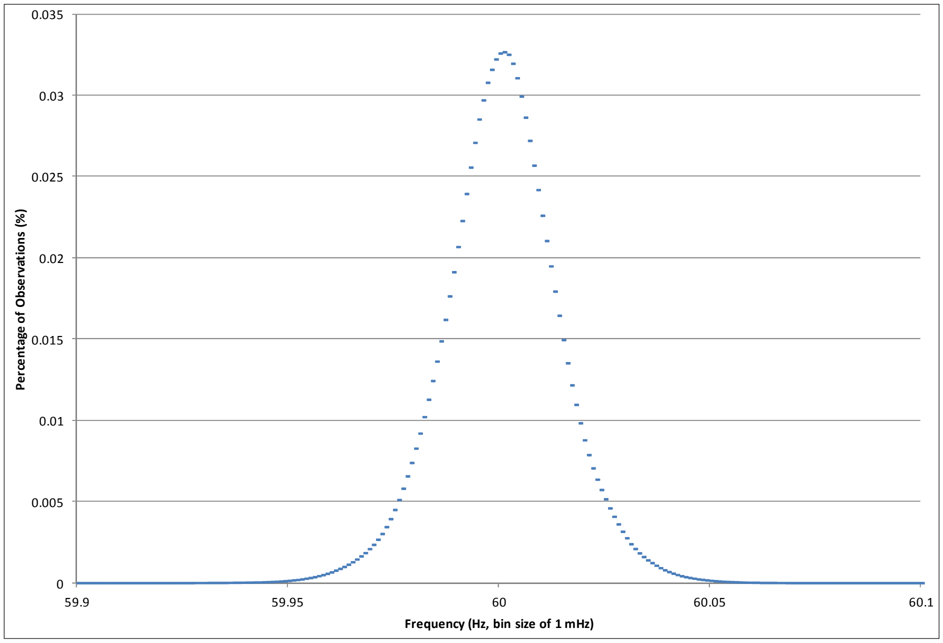
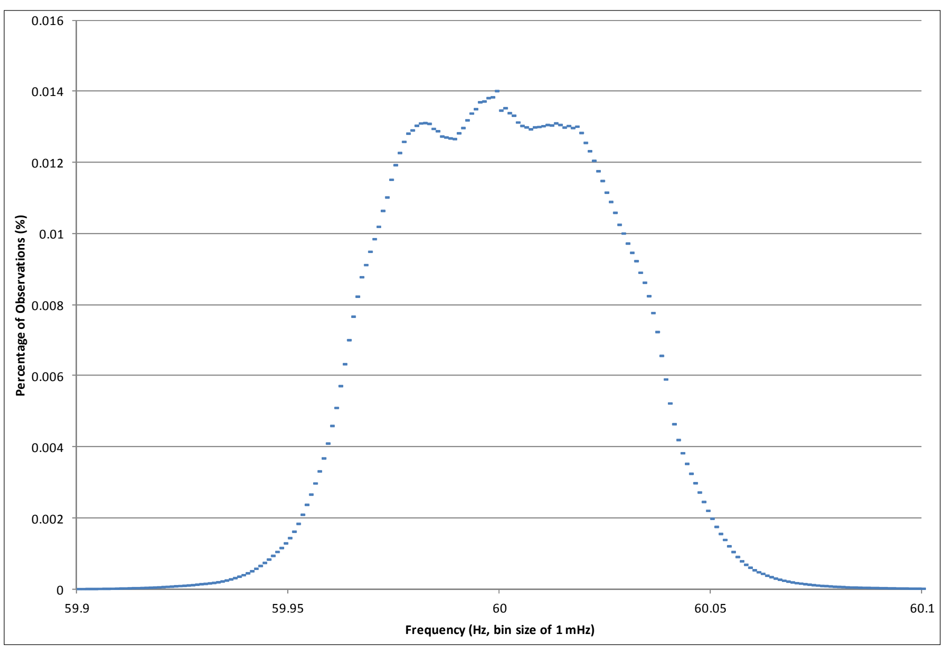
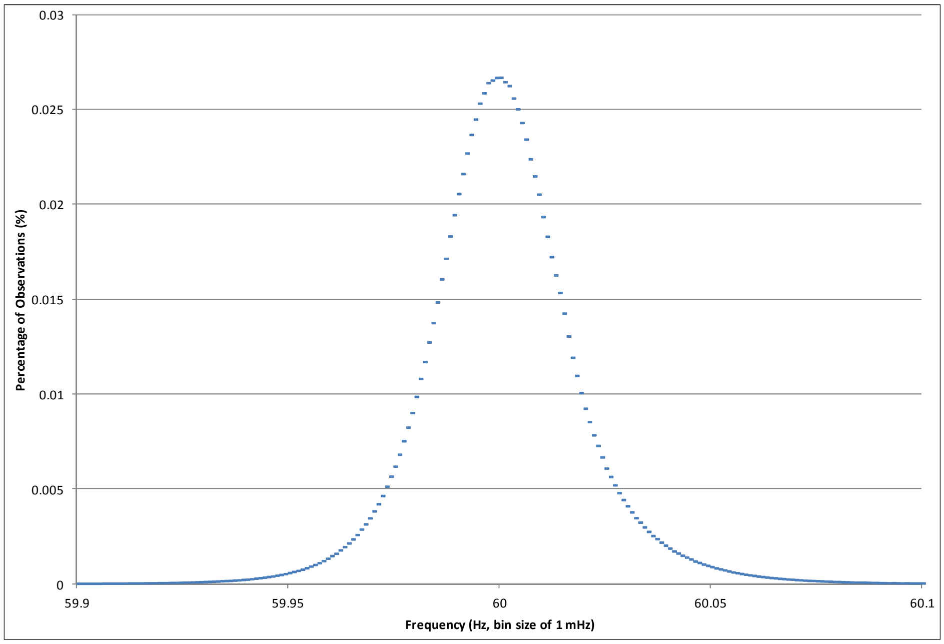


Figure 32: ERCOT Interconnection 2007-2011 Frequency Histogram



Note that the ERCOT frequency histogram displays the influence of the “flat-top” freneqcy profile that was common to that interconnection prior to 2008. That phenomenon was caused by a standardized ± 36 mHz deadband with a step-function implementation. Additional discussion on that topic is in the ERCOT Experience section of this report.

Figure 33: Québec Interconnection 2010-2011 Frequency Histogram



Point C Analysis – 1-Second versus Sub-Second Data

Additional statistical analysis was performed for the differences between Point C and Value B calculated as a ratio of Point C to Value B using 1-second data for events from December 2010 through May 2012. Although the 1-second data sample is robust, it does not necessarily ensure capturing the nadir of the event. To do so requires sub-second measurements that can only be provided by PMUs or FDRs. Therefore, a "CC" adjustment component (CC_{ADJ}) for the IFRO calculation was designed to account for the differences observed between the 1-second Point C and high-speed Point C measurements from the FNet FDRs.

Table 4: Analysis of 1-Second and Sub-Second Data for Point C (CC_{ADJ})

Interconnection	Number of Samples	Mean	Standard Deviation	CC_{ADJ} (95% Quantile)
Eastern	30	0.0006	0.0038	0.0068
Western	17	0.0012	0.0019	0.0044
ERCOT	58	0.0021	0.0061	0.0121
Québec	0	N/A	N/A	N/A

This adjustment should be made to the allowable frequency deviation value before it is adjusted for the ratio of Point C to Value B. Note: no sub-second data was available for the Québec Interconnection.

RECOMMENDATION – The allowable frequency deviation (starting frequency minus the highest UFLS step) should be reduced by the CC_{ADJ} to account for differences between the 1-second and sub-second data for Point C as listed in Table B-C9.

Adjustment for Differences between Value B and Point C

All of the calculations of the IFRO are based on protecting from instantaneous or time-delayed tripping of the highest step of UFLS, either for the initial nadir (Point C), or for any lower frequency that might occur during the frequency event. The frequency variance analysis in the previous section of this report is based on 1-second data from 2007 through 2011 (except Québec 2010 and 2011 only).

As a practical matter, the ability to measure the tie line and loads for the Balancing Authorities is limited to system control and data acquisition (SCADA) scan-rate data of 1 to 6 seconds. Therefore, the ability to measure frequency response of the Balancing Authorities is still limited by the SCADA scan rates available to calculate Point B.

An analysis of the relationship between Value B and Point C from for the significant frequency disturbances from December 2010 through May 2012 that were deemed candidates for frequency response analysis in accordance with the ALR1-12 Metric Event Selection Process (Appendix E). This sample set was selected because data was available for the analysis on a consistent basis. This resulted in the number of events shown in Table 5.

Analysis Method

When evaluating some physical systems, the nature of the system and the data resulting from measurements derived from that system do not fit the standard Linear Regression methods that allow for both a slope and an intercept for the regression line. In those cases, it is better to use a linear regression technique that represents the system correctly.

The Interconnection Frequency Response Obligation is a minimum performance level that must be met by the Balancing Authorities in an interconnection. Such response is expected to come from the Frequency Response in MWs of the Balancing Authorities to a change in frequency. As such, if there is no change in frequency there should be no change in MWs resulting from Frequency Response.

This response is also related to the function of the Frequency Bias setting in the ACE equation of the Balancing Authorities for longer-term. The ACE Equation looks at the difference between Scheduled Frequency and Actual Frequency times the Frequency Bias Setting to estimate the amount of MWs that are being provided by load and generation within the Balancing Authority. If the Actual Frequency is equal to the scheduled frequency, the Frequency Bias component of ACE must be zero.

Since the IFRO is ultimately a projection of how the interconnection is expected to respond to changes in frequency related to a change in MW (resource loss or load loss), there should be no expectation of Frequency Response without an attendant change in MW. It is this relationship that indicates the appropriateness of the use of regression with a forced fit through zero.

Evaluation of Data to determine C to B Ratio:

The evaluation of data to determine C to B Ratio to account for the differences between of Arrested Frequency Response (to the nadir, Point C) and the Settled Frequency Response (Value B) is also based on a physical representation of the electrical system. Evaluation of this system requires investigation of the meaning of an intercept. The C to B Ratio is defined as the difference between the pre-disturbance frequency and the frequency at the maximum deviation in post disturbance frequency, divided by the difference between the predisturbance frequency and the settle post disturbance frequency.

$$CB_R = \frac{Value\ A - Point\ C}{Value\ A - Value\ B}$$

A stable physical system requires the ratio to be positive; a negative ratio indicates frequency instability or recovery of frequency greater than the initial deviation.

Table 5: Analysis of Value B and Point C (CB_R)				
Interconnection	Number of Samples	Mean	Standard Deviation	CB_R (95% Quantile)
Eastern	41	0.964	0.0149	1.0 (0.989)[19]
Western	30	1.570	0.0326	1.625
ERCOT	88	1.322	0.0333	1.377
Québec	26	3.280	0.1952	3.613

Since this statistical analysis was completed using 1-second averaged data that cannot account for the C point of the interconnection, which is better measured by high-speed metering (PMUs or FDRs). Therefore, a separate correction must be used to account for the differences between the Point C in the 1-second data, and the Point C values measured with sub-second measurements from the FNet FDRs.

The CB_R value for the Eastern Interconnection indicates that the Value B is generally below the Point C value. Therefore, there is no adjustment necessary for that interconnection.

Variables in Determination of Interconnection Frequency Response Obligation from Criteria

To make a determination of the appropriate Resource Contingency Protection Criteria to protect for a certain kind of event, the MW target value needs to be translated into an Interconnection Frequency Response Obligation (IFRO) for an appropriate comparison. A number of other variables must be taken into consideration.

[19] CB_R value limited to 1.0 because values lower than that indicate the Value B is lower than Point C and does not need to be adjusted. The calculated value is 0.989.

Low Frequency Limit

The low frequency limit to be used for the IFRO calculations should be the highest setpoint in the interconnection for regionally approved UFLS systems.

RECOMMENDATION – Using the tenet that UFLS should not trip for a frequency event throughout the interconnection the recommended UFLS first-step limitations for IFRO calculations are listed in Table 6

Table 6: Low Frequency Limits (Hz)	
Interconnection	Highest UFLS Trip Frequency
Eastern	59.7
Western	59.5
ERCOT	59.3
Québec	58.5

The highest UFLS setpoint in the Eastern Interconnection is 59.7 Hz in FRCC, while the prevalent highest setpoint rest of that interconnection is 59.5 Hz.

Protection against tripping the highest step of UFLS does not ensure that generation that has frequency-sensitive protection or turbine control systems will not trip. During sever system conditions that might drive the frequency to those levels may present those protection and control system with a combination conditions that may cause the generation to trip, such as severe rate-of-change in voltage or frequency, which might actuate volts per Hertz relays. Similarly, some combustion turbines may not be able to sustain operation at frequencies below 59.5 Hz. Similarly, recent laboratory testing by Southern California Edison of inverters used on residential and commercial scale photovoltaic (PV) systems have revealed a propensity to trip at about 59.4 Hz, which is 200 mHz above the expected 59.2 Hz prescribed in IEEE Standard 1547 for distribution-connected PV rating ≤ 30 kW (57.0Hz for larger installations). This could become problematic in areas of high penetration of photovoltaic resources.

Credit for Load Resources (CLR)

The ERCOT Interconnection depends on contractually interruptible demand that automatically trips at 59.7 Hz to help arrest frequency declines. A 1,400 MW LR (formerly Load acting as a Resource – LaaR) credit is included against the Resource Contingency for the ERCOT Interconnection. Similarly, there is a remedial action scheme (RAS) in the WECC that trips 300 MW of load for the loss of two Palo Verde generating units.

For the Western Interconnection, however, if the larger 3,200 MW resource loss is used associated with the RAS activated by the tripping of the Pacific DC Intertie (PDCI) when loaded to 3,200 MW, the 300 MW credit for Load Resources from the RAS associated with the loss of two Palo Verde units does not apply.

For both interconnections credit for load resources are handled in the calculation of the IFRO as a reduction to the loss of resources, when appropriate.

Interconnection Resource Contingency Protection Criteria

Selection of discrete event protection criteria for each interconnection must be done before the IFRO can be calculated. The protection criteria selected should assure that Point C will not encroach on the first step UFLS. However, the criteria may need to be different from one interconnection to the other due to the differences in size and design characteristics.

The following potential Interconnection event criteria were considered:

- Largest N-2 loss-of-resource event
- Largest total generating plant with common voltage switchyard
- Largest loss of generation in the interconnection in the last 10 years

Largest N-2 Event

For this approach, each Interconnection will have a target Resource Contingency Protection Criteria based on the largest N-2 loss-of-resource event. This should not be confused with a Category C, N-2 event prescribed in the NERC TPL standards; it is intended to reflect a simultaneous loss of the resources without time for system adjustments. As such, this is a Category D event in the standards.

For both the ERCOT and Western Interconnections, that would be the loss of the two largest generating units in the interconnection. However, for the Eastern Interconnection, the largest N-2 loss-of-resource event would be the loss of the two Nelson DC bi-pole converters.

Table 7: Largest N-2 Event

Interconnection	Basis	MW
Eastern	Nelson DC Bi-poles 1 & 2	3,854[20]
Western	Two Palo Verde Units	2,740[21]
ERCOT	Two South Texas Project Units	2,750[22]

[20] Nelson Bi-poles 1 & 2 are rated 1,854 MW and 2,000 MW, respectively.

[21] Net winter ratings per Form EIA-860 reporting.

[22] Net rating from ERCOT Resource Asset Registration Form (RARF).

Largest Total Plant with Common Voltage Switchyard

Another approach is to examine the largest complete generating plant outage in each of the interconnections, limiting this classification to those generators with a common voltage switchyard. The reasoning for considering such a protection criteria is that despite popular belief, complete plant outages can and do happen on a regular basis; fifteen complete plant outages occurred in North America in the 12 months from July 1, 2010 through June 30, 2011.

Table 8: Largest Total Plant with Common Voltage Switchyard		
Interconnection	Basis	MW
Eastern	Darlington Units 1-4	3,524[23]
Western	3 Palo Verde Units	3,575[24]
ERCOT	2 South Texas Project Units	2,750[25]

Note that in the Western Interconnection, a larger multi-plant generation tripping scheme due to operation of the Pacific Northwest remedial action scheme (RAS) results in loss of 3,200 MW of generation. That issue is further discussed in the Special IFRO Considerations section of this report.

Largest Resource Event in Last 10 Years

A third approach is to examine the largest complete resource loss event in the interconnection over the last 10 years. Although this method yields a reasonable value for the Eastern Interconnection, the values for the other two interconnections would likely not be sustainable without activating some UFLS. It also results in a larger resource contingency for the Western Interconnection than for the Eastern Interconnection. These single events were not approached in magnitude by any other events in the 10-year period.

Table 9: Largest Resource Contingency Event in Last 10 Years		
Interconnection	Basis	MW
Eastern	August 4, 2007 Disturbance	4,500
Western	June 14, 2004 Disturbance	5,000
ERCOT	May 15, 2003 Disturbance	3,400

23 Net winter ratings from the NERC Electricity Supply and Demand.

24 Net winter ratings per Form EIA-860 reporting.

25 Net rating from ERCOT Resource Asset Registration Form (RARF).

Recommended Resource Contingency Protection Criteria

Because the philosophy for the criteria is to protect against the largest frequency excursion the interconnection can withstand, the contingency criteria may vary significantly between the interconnections. For example, because of its sheer size and generating capacity, the Eastern Interconnection can withstand a far larger loss of resources.

Therefore, a blending of Resource Contingency Protection Criteria is recommended (Table 4) for the determination of IFROs.

Table 10: Recommended Resource Contingency Protection Criteria

Interconnection	Resource Contingency	Basis	MW
Eastern	Largest Resource Event in Last 10 Years	August 4, 2007 Disturbance	4,500
Western	Largest N-2 Event	2 Palo Verde Units	2,740[26]
ERCOT	Largest N-2 Event	2 South Texas Project Units	2,750[27]

Although the size of a resource contingency that can be sustained by an interconnection should be tested through dynamic simulations, that test can currently only be done for the Western and ERCOT Interconnections.

Recommendation – Dynamic simulation testing of the Western and ERCOT Resource Contingency Protection Criteria should be conducted as soon as possible.

Recommendation – Dynamic simulation testing of the Eastern Interconnection Resource Contingency Protection Criteria should be conducted when the dynamic simulation models of the interconnection are capable of performing the analysis.

26 Net winter ratings per Form EIA-860 reporting.

27 Net rating from ERCOT Resource Asset Registration Form (RARF).

Comparison of Alternative IFRO Calculations

Each of the proposed Resource Loss criteria alternatives were compared through development of the corresponding IFROs. The following tables show the calculation of an IFRO for each alternative for the Eastern, Western, and ERCOT Interconnections. The criterion for the Québec Interconnection was not modified.

IFRO Formulae

The following are the formulae that comprise the calculation of the IFROs.

$$DF_{Base} = F_{Start} - UFLS$$

$$DF_{CC} = DF_{Base} + CC_{Adj}$$

$$ADF = \frac{DF_{CC}}{CB_R}$$

$$ARLPC = RLPC - CLR$$

$$IFRO = \frac{ARLPC}{ADF}$$

Where:

- DF_{Base} is the base delta frequency.
- F_{Start} is the starting frequency determined by the statistical analysis.
- UFLS is the highest UFLS trip setpoint for the interconnection.
- DF_{CC} is the delta frequency adjusted for the differences between 1-second and sub-second Point C observations for frequency events.
- CB_R is the statistically determined ratio of the Point C to Value B to adjust the allowable delta frequency to account for that difference in the determination of the
- ADF is the adjusted delta frequency
- RLPC is the resource loss protection criteria.
- CLR is the credit for load resources.
- ARLPC is the adjusted resource loss protection criteria adjusted for the credit for load resources.
- IFRO is the interconnection frequency response obligation.

Largest N-2 Event

Table 11 shows the determination of IFROs based on a resource loss equivalent to the Largest N-2 event in each interconnection. This calculation has been adjusted to include the recommended adjustment for the differences between Value B and Point C, and for the differences in measurement of Point C using 1-second and sub-second data.

Table 11: Largest N-2 Event					
	Eastern	Western	ERCOT	Québec	
Starting Frequency	59.973	59.977	59.961	59.972	Hz
Minimum Frequency Limit	59.700	59.500	59.300	58.500	Hz
Base Delta Frequency	0.273	0.477	0.661	1.472	Hz
CC_{ADJ}	0.007	0.004	0.012	N/A	Hz
Delta Frequency$_{-C}$	0.266	0.473	0.649	1.472	Hz
CB_R	1.000[28]	1.625	1.377	3.613	Hz
Max. Delta Frequency (DF_{CC}/CB_R)	0.266	0.291	0.471	0.407	Hz
Resource Contingency Protection Criteria	3,854	2,740	2,750	1,700	MW
Credit for LR		300	1,400		MW
IFRO	-1,449	-838	-286	-417	MW/0.1Hz
Absolute Value of IFRO	1,449	838	286	417	MW/0.1Hz
% of Current Interconnection Performance[29]	58.7 %	71.0 %	48.9 %	N/A	
% of Interconnection Load[30]	0.24 %	0.56 %	0.45 %	2.03 %	

Largest Total Plant with Common Voltage Switchyard

Table 12 shows the determination of IFROs based on a resource loss equivalent to the Largest Total Plant with Common Voltage Switchyard in each interconnection. This calculation has

[28] CB_R value for the Eastern Interconnection limited to 1.0 because values lower than that indicate the Value B is lower than Point C and does not need to be adjusted. The calculated value is 0.989.

[29] Current Interconnection Frequency Response Performance: EI = -2,467 MW / 0.1Hz, WI = -1,179 MW / 0.1Hz, TI = -586 MW / 0.1Hz, and QI = N/A.

[30] Interconnection projected Total Internal Demands from the 2010 NERC Long-Term Reliability Assessment: EI = 604,245 MW, WI = 148,895 MW, TI = 63,810 MW, and QI = 20,599 MW.

been adjusted to include the recommended adjustment for the differences between Value B and Point C, and for the differences in measurement of Point C using 1-second and sub-second data.

Table 12: Largest Total Plant with Common Voltage Switchyard					
	Eastern	Western	ERCOT	Québec	
Starting Frequency	59.973	59.977	59.961	59.972	Hz
Minimum Frequency Limit	59.700	59.500	59.300	58.500	Hz
Base Delta Frequency	0.273	0.477	0.661	1.472	Hz
CC_{ADJ}	0.007	0.004	0.012	N/A	Hz
Delta $Frequency_{-C}$	0.266	0.473	0.649	1.472	Hz
CB_R	1.000[31]	1.625	1.377	3.613	Hz
Max. Delta Frequency (DF_{CC}/CB_R)	0.266	0.291	0.471	0.407	Hz
Resource Contingency Protection Criteria	3,524	3,575	2,750	1,700	MW
Credit for LR		300	1,400		MW
IFRO	-1,325	-1,330	-286	-417	MW/0.1Hz
Absolute Value of IFRO	1,325	1,330	286	417	MW/0.1Hz
% of Current Interconnection Performance[32]	53.7 %	112.8 %	48.9 %	N/A	
% of Interconnection Load[33]	0.22 %	0.89 %	0.45 %	2.03 %	

Largest Resource Event in Last 10 Years

Table 13 shows the determination of IFROs based on a resource loss equivalent to the Largest Resource Event in Last 10 Years in each interconnection. This calculation has been adjusted to include the recommended adjustment for the differences between Value B and Point C, and for the differences in measurement of Point C using 1-second and sub-second data.

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31 CB_R value for the Eastern Interconnection limited to 1.0 because values lower than that indicate the Value B is lower than Point C and does not need to be adjusted. The calculated value is 0.989.

32 Current Interconnection Frequency Response Performance: EI = -2,467 MW / 0.1Hz, WI = -1,179 MW / 0.1Hz, TI = -586 MW / 0.1Hz, and QI = N/A.

33 Interconnection projected Total Internal Demands from the 2010 NERC Long-Term Reliability Assessment: EI = 604,245 MW, WI = 148,895 MW, TI = 63,810 MW, and QI = 20,599 MW.

Table 13: Largest Resource Event in Last 10 Years					
	Eastern	Western	ERCOT	Québec	
Starting Frequency	59.973	59.977	59.961	59.972	Hz
Minimum Frequency Limit	59.700	59.500	59.300	58.500	Hz
Base Delta Frequency	0.273	0.477	0.661	1.472	Hz
CC_{ADJ}	0.007	0.004	0.012	N/A	Hz
Delta $Frequency_{-C}$	0.266	0.473	0.649	1.472	Hz
CB_R	1.000[34]	1.625	1.377	3.613	Hz
Max. Delta Frequency (DF_{CC}/CB_R)	0.266	0.291	0.471	0.407	Hz
Resource Contingency Protection Criteria	4,500	5,000	3,400	1,700	MW
Credit for LR		300	1,400		MW
IFRO	-1,692	-1,716	-424	-417	MW/0.1Hz
Absolute Value of IFRO	1,692	1,716	424	417	MW/0.1Hz
% of Current Interconnection Performance[35]	68.6 %	145.6 %	72.4 %	N/A	
% of Interconnection Load[36]	0.28 %	1.15 %	0.67 %	2.03 %	

Recommended IFROs

Table 14 shows the determination of IFROs based on a resource loss equivalent to the Recommended Criteria in each interconnection. This calculation has been adjusted to include the recommended adjustment for the differences between Value B and Point C, and for the differences in measurement of Point C using 1-second and sub-second data.

RECOMMENDATION – The Interconnection Frequency Response Obligations should be calculated as shown in Table 14 – Recommended IFROs.

Table 14: Recommended IFROs

[34] CB_R value for the Eastern Interconnection limited to 1.0 because values lower than that indicate the Value B is lower than Point C and does not need to be adjusted. The calculated value is 0.989.

[35] Current Interconnection Frequency Response Performance: EI = -2,467 MW / 0.1Hz, WI = -1,179 MW / 0.1Hz, TI = -586 MW / 0.1Hz, and QI = N/A.

[36] Interconnection projected Total Internal Demands from the 2010 NERC Long-Term Reliability Assessment: EI = 604,245 MW, WI = 148,895 MW, TI = 63,810 MW, and QI = 20,599 MW.

	Eastern	Western	ERCOT	Québec	
Starting Frequency	59.973	59.977	59.961	59.972	Hz
Minimum Frequency Limit	59.700	59.500	59.300	58.500	Hz
Base Delta Frequency	0.273	0.477	0.661	1.472	Hz
CC_{ADJ}	0.007	0.004	0.012	N/A	Hz
Delta $Frequency_{-C}$	0.266	0.473	0.649	1.472	Hz
CB_R	1.000[37]	1.625	1.377	3.613	Hz
Max. Delta Frequency (DF_{CC}/CB_R)	0.266	0.291	0.471	0.407	Hz
Resource Contingency Protection Criteria	4,500	2,740	2,750	1,700	MW
Credit for LR		300	1,400		MW
IFRO	-1,692	-838	-286	-417	MW/0.1Hz
Absolute Value of IFRO	1,692	838	286	417	MW/0.1Hz
% of Current Interconnection Performance[38]	68.6 %	71.0 %	48.9 %	N/A	
% of Interconnection Load[39]	0.28 %	0.56 %	0.45 %	2.03 %	

Special IFRO Considerations

The IFRO calculation scenarios for the Western Interconnection do not take into account intentional tripping of generation during the operation of remedial action schemes (RAS). A key example is the Pacific Northwest RAS for loss of the Pacific DC Intertie (PDCI) which trips up to 3,200 MW of generation in the Pacific Northwest when the PDCI trips, depending on the loading of the PDCI. The RAS is intended to avoid system instability, tripping generation, inserting the Chief Joseph braking resistor (for up to 30 cycles), and other reactive configuration changes. However, because the generation in the Pacific Norwest is some of the most responsive to frequency deviations in the Western Interconnection, the RAS also blocks Frequency Response by a number of generators and Balancing Authorities to avoid overloading the Pacific AC ties (such as the California-Oregon Interface – COI).

37 CB_R value for the Eastern Interconnection limited to 1.0 because values lower than that indicate the Value B is lower than Point C and does not need to be adjusted. The calculated value is 0.989.

38 Current Interconnection Frequency Response Performance: EI = -2,467 MW / 0.1Hz, WI = -1,179 MW / 0.1Hz, TI = -586 MW / 0.1Hz, and QI = N/A.

39 Interconnection projected Total Internal Demands from the 2010 NERC Long-Term Reliability Assessment: EI = 604,245 MW, WI = 148,895 MW, TI = 63,810 MW, and QI = 20,599 MW.

Frequency events caused by the 3,200 MW generation trips from that RAS have been historically not considered as candidate events for the Western Interconnection calculation of Frequency Bias settings by the Balancing Authorities because of the response blocking. However, from an interconnection perspective, the frequency of the interconnection still has to be maintained as a whole, regardless of which Balancing Authorities are responding to the event. This creates a dilemma when calculating an IFRO for the interconnection – the resultant resource loss is larger than the design loss criteria of two Palo Verde Units (2,440 MW). Table XX shows a comparison of the two resource losses in calculating the IFRO for the Western Interconnection.

Table 15: Western Interconnection IFRO Comparison			
	2-PV	**PNW RAS**	
Starting Frequency	59.977	59.977	Hz
Minimum Frequency Limit	59.500	59.500	Hz
Base Delta Frequency	0.477	0.477	Hz
CC_{ADJ}	0.004	0.004	Hz
Delta $Frequency_{-C}$	0.473	0.473	Hz
CB_R	1.625	1.625	Hz
Max. Delta Frequency(DF_{CC}/CB_R)	0.291	0.291	Hz
Resource Contingency Protection Criteria	2,740	3,200	MW
Credit for LR	300		MW
IFRO	-838	-1,098	MW/0.1Hz
Absolute Value of IFRO	838	1,098	MW/0.1Hz
% of Current Interconnection Performance[40]	71.0 %	93.2 %	
% of Interconnection Load[41]	0.56 %	0.74 %	

Using a 3,200 MW resource loss criterion in the IFRO calculation increases the obligation by 260 MW, but is further complicated when that obligation is allocated to the Balancing Authorities in the interconnection; allocation of FOR to Balancing Authorities whose response is blocked by the RAS is inappropriate. Therefore, a different FRO allocation would be necessary for that IFRO.

Recommendation – NERC and the Western Interconnection should analyze the FRO allocation implications of the Pacific Northwest RAS generation tripping of 3,200 MW..

Comparison of IFRO Calculations

Table 14 shows a comparison of the 4 criteria analyzed by the TIS, as well as the criteria recommended by the NERC Resources Subcommittee (RS) in their whitepaper on frequency

[40] Current Interconnection Frequency Response Performance: WI = -1,179 MW / 0.1Hz.

[41] Interconnection projected Total Internal Demands from the 2010 NERC Long-Term Reliability Assessment: WI = 148,895 MW.

response. The table also compares the IFROs to current levels of frequency response performance[42] for each of the interconnections. A comparison is also made to IFROs adjusted to include the recommended adjustment for the differences between Value B and Point C.

Table 16: IFRO Calculation Comparison

	Eastern	Western	ERCOT	Québec	
Current Interconnection Frequency Response Performance	-2,467	-1,179	-586	N/A	MW/0.1Hz
Largest N-2 Event					
Resource Loss Criteria	3,854	2,740	2,750	1,700	MW
IFRO	-1,449	-838	-286	-417	MW/0.1Hz
IFRO as % of Current Performance	58.7 %	71.0 %	48.9 %	N/A	
IFRO as % of Load[43]	0.24 %	0.56 %	0.45 %	2.03 %	
Largest Total Plant with Common Voltage Switchyard					
Resource Loss Criteria	3,524	3,575	2,750	1,700	MW
IFRO	-1,325	-1,330	-2868	-417	MW/0.1Hz
IFRO as % of Current Performance	53.7 %	112.8 %	48.9 %	N/A	
IFRO as % of Load	0.22 %	0.89 %	0.45 %	2.03 %	
Largest Resource Event in Last 10 Years					
Resource Loss Criteria	4,500	5,000	3,400	1,700	MW
IFRO	-1,692	-1,716	-424	-417	MW/0.1Hz
IFRO as % of Current Performance	68.6 %	145.6 %	72.4 %	N/A	
IFRO as % of Load	0.28 %	1.15 %	0.67 %	2.03 %	

Table 17 compares the recommended IFROs with those recommended by the Resources Subcommittee and those currently recommended by the Frequency response Standard Drafting Team.

[42] Based on the frequency response performance calculated in the daily CERTS-EPG Automated Reliability Reports for 2011 through August 16, 2011.

[43] Interconnection projected Total Internal Demands from the 2010 NERC Long-Term Reliability Assessment: EI = 604,245 MW, WI = 148,895 MW, TI = 63,810 MW, and QI = 20,599 MW.

Table 17: IFRO Calculation Comparison					
	Eastern	**Western**	**ERCOT**	**Québec**	
Current Interconnection Frequency Response Performance	-2,467	-1,179	-586	N/A	MW/0.1Hz
Recommended IFROs					
Resource Loss Criteria	4,500	2,740	2,750	1,700	MW
IFRO	-1,692	-838	-286	-417	MW/0.1Hz
IFRO as % of Load	0.28 %	0.56 %	0.45 %	2.03 %	
RS Recommendation					
Resource Loss Criteria	4,500	2,740	2,750	1,700	MW
Base IFRO	-1,125	-548	-229	-113	MW/0.1Hz
25 % Margin	-281	-137	-57	-28	MW/0.1Hz
IFRO	-1,406	-685	-286	-141	MW/0.1Hz
IFRO as % of Load	0.23 %	0.46 %	0.45 %	0.68 %	
FRRSDT Recommendation (from Attachment A to the BAL-003 Draft Standard)					
Resource Loss Criteria	4,500	2,740	2,750	1,700	MW
Base IFRO	-972	-548	-229	-113	MW/0.1Hz
25 % Margin	-243	-167	-60	-61	MW/0.1Hz
IFRO	-1,215	-836	-299	-305	MW/0.1Hz
IFRO as % of Load	0.20 %	0.56 %	0.47 %	1.48 %	

Allocation of IFRO to Balancing Authorities

The allocation of the IFRO to individual Balancing Authorities in a multi-Balancing Authority interconnection will be done in accordance with the "Attachment A – BAL-003-1 Frequency Response and Frequency Bias Setting Supporting Document" which can be found at:

http://www.nerc.com/docs/standards/sar/Att_A_Freq_Response_Standard_Support_Document_100611.pdf)

The process is paraphrased here for brevity.

Once the IFROs have been calculated by the ERO, the FRO for each Balancing Authority in a multi-Balancing Authority interconnection is allocated based on the Balancing Authority annual load and annual generation to each Balancing Authority by the following formula:

$$FRO_{BA} = FRO_{Int}\,X\,\frac{AnnualGen_{BA} + AnnualLoad_{BA}}{AnnualGen_{Int} + AnnualLoad_{Int}}$$

Where:

- Annual Gen_{BA} is the total annual "Output of Generating Plants" within the Balancing Authority Area (BAA), on FERC Form 714, column C of Part II - Schedule 3.
- Annual Load_{BA} is total annual Load within the BAA, on FERC Form 714, column E of Part II - Schedule 3.
- Annual Gen_{Int} is the sum of all Annual Gen_{BA} values reported in that interconnection.
- Annual Load_{Int} is the sum of all Annual Load_{BA} values reported in that interconnection.

The data used for this calculation is from the most recently filed Form 714. As an example, a report to NERC in January 2013 would use the Form 714 data filed in 2012, which used data from 2011. Balancing Authorities that are not FERC jurisdictional will use the Form 714 Instructions to assemble and submit equivalent data to the ERO for use in the FRO Allocation process.

Balancing Authorities that elect to form a Frequency Response Sharing Group (FRSG) will calculate a FRSG FRO by summing the individual Balancing Authority FROs. Balancing Authorities that elect to form a FRSG as a means to jointly meet the FRO will calculate their FRM performance for the FRS Form 1 as follows:

- Calculate a group NIA and measure the group response to all events in the reporting year on a single FRS Form 1, or
- Jointly submit the individual BAs' Form 1s, with a summary spreadsheet that sums each participant's individual event performance.

Balancing Authorities that merge or transfer load or generation are encouraged to notify the ERO of the change in footprint and corresponding changes in allocation such that the net obligation to the Interconnection remains the same and so that CPS limits can be adjusted.

Each Balancing Authority reports its previous year's Frequency Response Measure (FRM), Frequency Bias Setting and Frequency Bias type (fixed or variable) to the ERO each year to allow the ERO to validate the revised Frequency Bias Settings on FRS Form 1. If the ERO posts the official list of events after the date specified in the timeline below, Balancing Authorities will be given 30 days from the date the ERO posts the official list of events to submit their FRS Form 1.

Once the ERO reviews the data submitted in FRS Form 1 and FRS Form 2 for all Balancing Authorities, the ERO will use FRS Form 1 data to post the following information for each Balancing Authority for the upcoming year:

- Frequency Bias Setting
- Frequency Response Obligation (FRO)

A Balancing Authority providing Overlap Regulation will report the historic peak demand and generation of its combined BAs' areas on FRS Form 1 as described in Requirement R4 of the BAL-003 Standard.

Frequency Response Performance Measurement

Interconnection Process

The process for detection of candidate interconnection frequency events for use in frequency response metrics is described in the “ALR1-12 Metric Event Selection Process” contained in Appendix W. It is paraphrased here for brevity.

Frequency Event Detection, Analysis, and Trending (for metrics and analysis)

Interconnection frequency events are detected through a number of systems including:

- FNet (Frequency monitoring Network) – FNet is a wide-area power system frequency measurement system that uses a type of phasor measurement unit (PMU) known as a Frequency Disturbance Recorder (FDR). FNET is able to measure the power system frequency, voltage, and angle very accurately at a rate of 10 samplers per second. The FNET system is currently operated by the Power Information Technology Laboratory at Virginia Tech and the University of Tennessee, Knoxville. FNet alarms are received by the NERC Situational Awareness staff and contain an estimate of the size of the resource or load loss and general location description based on triangulation between FDRs.
- CERTS-EPG Resource Adequacy Tool Intelligent Alarms – The Electric Power Group (EPG) operates the Resource Adequacy (RA) tool developed under the auspices of the Consortium for Electric Reliability Technology Solutions (CERTS). The RA tool uses 1-minute frequency and Area Control Error (ACE) SCADA data transmitted to a NERC central database. The RA tool constantly monitors frequency and produces many Smart Alarms for a number of frequency change conditions, but most useful for frequency event detection is the short-term frequency deviation alarm, which indicates when there has been a significant change in frequency over the last few minutes, typically indicating a resource loss.
- CERTS-EPG Frequency Monitoring and Analysis (FMA) Tool – EPG also developed and operates the FMA tool that allows rapid analysis of frequency events, calculating the A, B and C values for a frequency event in accordance with parameters set by the Frequency Working Group (FWG). Event selection criteria are further discussed in Appendix E of this report

Those three systems are used in combination by NERC staff to detect and collect data about frequency excursions in the four North American interconnections. The size of resource losses is verified with the Regional Entities for events where FNet estimates of resource loss meet the following criteria:

- Eastern – > 1,000 MW (60 mHz excursion)
- Western – > 700 MW (80 mHz excursion)

- ERCOT – > 450 MW (100 mHz excursion)

The events that detected and meet the ALR1-12 Metric criteria are then considered to be "candidate events" and are used by the NERC staff to calculate interconnection frequency response metrics and trends. Those candidate events are also presented to the Frequency Working Group for consideration to be used as events for calculation of Balancing Authority Frequency Response and Bias setting calculations in accordance with Standard BAL-003.

Ongoing Evaluation

The process for detection of frequency events and the calculation of Values A, B, and C and the associated interconnection level metrics will undergo constant review in an effort to improve the process. That review will be performed at least annually by NERC staff and the Frequency Working Group.

Recommendation – The NERC staff and the Frequency Working Group should annually review the process for detection of frequency events and the calculation of Values A, B, and C and the associated interconnection level metrics will undergo constant review in an effort to improve the process.

Balancing Authority Level Measurements

A statistical analysis and evaluation was performed on field trial data with similar sample sizes to those specified in the draft Standard BAL-003-1 Frequency Response and Frequency Bias Setting. Field Trial data was provided on FRS Form 1 for 2011 for 60 Balancing Authorities on the Eastern and Western Interconnections; the analysis was not performed for either of the single Balancing Authority interconnections, ERCOT or Quebec. Of the 60 Balancing Authorities that provided data, only 50 provided data of sufficient quality to be used in the analysis. Balancing Authorities that were excluded provided frequency data that was either obviously incorrect (i.e., frequency data in Hertz instead of change in Hertz) or frequency data that was uncorrelated to the interconnection measured frequency.

To protect the confidential nature of the data, the Form 1 data was normalized by dividing the change in actual net interchange by the Frequency Response Obligation (FRO) for each BA, based on Interconnection Frequency Response Obligations (IFROs) of -1,215 Mw/0.1 Hz and -836 MW/0.1 Hz for the eastern and Western Interconnections, respectively.[44] This normalization method converts all of the data from the actual Frequency Response of the Balancing Authority to a per unit Frequency Response value where 1.0 indicates that the Frequency Response is exactly equal to the BA's FRO. The process also required the development of the some of the data that would appear on the equivalent of the CPS2 Bounds Report under this revised standard. The required data was extracted from the FERC Form No.

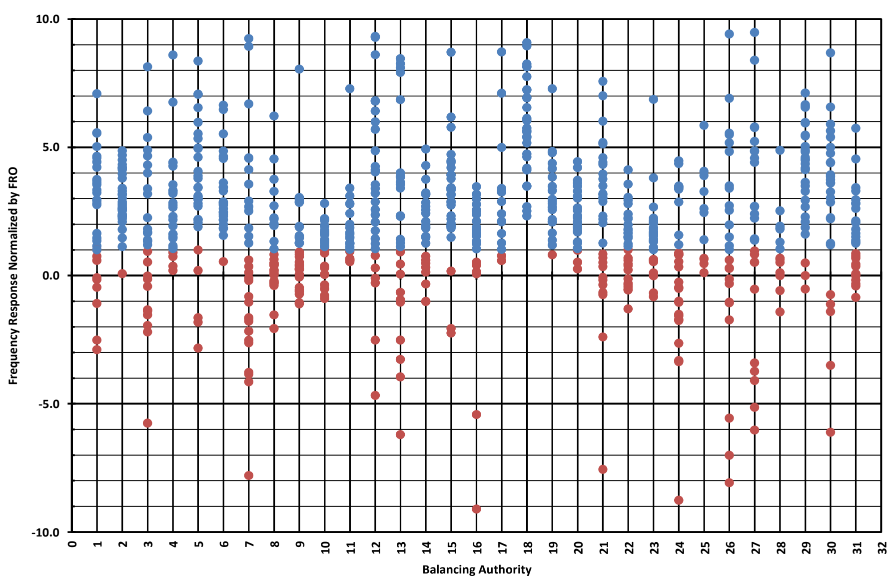
[44] As recommended by the Project 2007-12 Frequency Response Standards Drafting Team during the May 2012 Frequency Response Technical Conferences.

714 Reports for the year 2009, and was estimated for those Balancing Authorities that did not submit 714 Reports from equivalent data based on other sources. The validity of this analysis is not dependent upon the accuracy of the FRO estimates. It is only necessary for these estimates to be close to the actual values for firm conclusions to be drawn from the results and put the results in the proper context. Once the FROs were estimated for all of the Balancing Authorities on the Eastern and Western Interconnections, they were transcribed onto the FRS Form 1s for each Balancing Authority included in the analysis.

Single Event Compliance

The question of whether or not BAs' compliance with the proposed BAL-003 standard should be measured on each event, or through use of the mean, median, or a regression analysis for a 12 month period. The variability of the measurement of Frequency Response for an individual Balancing Authority for an individual Disturbance event was evaluated to determine its suitability for use as a compliance measure. The individual BA's performance Disturbance events were normalized and plotted for each Balancing Authority on the Eastern and Western Interconnections.

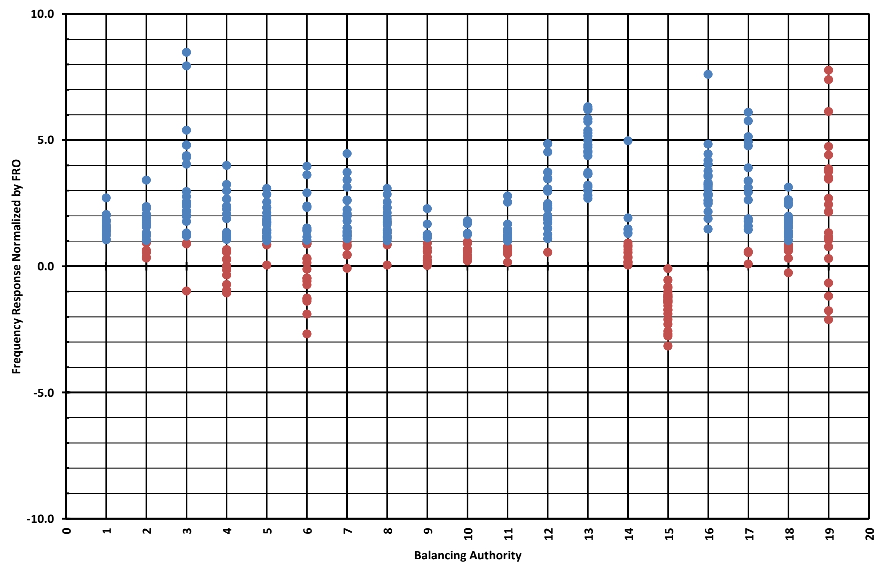
Figure 34: 2011 Normalized Frequency Response Events by BA Eastern Interconnection



On Figures 34 and 35, events that had a measured BA's Frequency Response above its FRO were shown as blue dots and events that had a measured Frequency Response below its FRO were shown as red dots.

Analysis of this data indicates that a single event based compliance measure is unsuitable for compliance evaluation when the data has the large degree of variability shown in the charts in Appendix 1. Based on the field trial data provided, only three out of 19 Balancing Authorities in the sample (16%) would be compliant for all events with a standard based on a single event measure on the Western Interconnection. Only one out of 31 Balancing Authorities in the sample (3%) would be compliant for all events with a standard based on a single event measure on the Eastern Interconnection.

Figure 35: 2011 Normalized Frequency Response Events by BA Western Interconnection



Finding – Analysis of the field trial data indicates that a single event based compliance measure is unsuitable for compliance evaluation when the data has the large degree of variability.

Recommendation – Balancing Authority compliance with Standard BAL-003 should not be judged on a per-event basis. Doing so would cause almost 90% of the Balancing Authorities to be out of compliance.

Balancing Authority Frequency Response Performance Measurement Analysis

Data provided by the Balancing Authorities from the field trial were also analyzed to determine: (i) if the sample size minimum of 20 to 25 frequency events, as specified for FRM calculation of the draft BAL-003 Standard, is sufficient to provide stable measurements results, and (ii) which of the three candidate FRM measurement methods is most appropriate. These analyses were carried out using the normalized data provided by a number of Balancing Authorities during the field trial.

Event Sample Size

Previous studies have recommended a sample size sufficient to provide a stable measure of Frequency Response of 20 to 25 events. These previous studies were performed on limited data and a limited number of Balancing Authorities. The field trial data set is sufficiently large to allow conclusions to be drawn with respect to that sample size recommendation specified for FRM calculation in the draft standard.

Review of the full set of graphs (Appendix H) indicates that the outlier problem, as previously described, did not present itself. There were no Balancing Authorities that had a small degree of variability in the measured single event Frequency Response for most of the events with a few outliers.

The variability appeared similar for all events for each BA, indicating that the sample size of 20 to 25 events is sufficient to stabilize the result and eliminate any undue influence from potential outliers. In those Balancing Authorities with large variations in measured single event response, the sample size was sufficient to collect enough samples that no single outliers unduly influenced the result as was feared. Balancing Authorities with large measurement variation still had enough samples to mitigate the risk associated with outliers. This demonstrates that the sample size chosen is sufficient to stabilize all three methods of measuring FRM. Therefore, it can be concluded that none of the methods are unduly influenced by outliers and the selection of the measurement method should be based on other factors.

Finding – Analysis of data submitted by the Balancing Authorities during the field trial confirms that the sample size selected (a minimum of 20 to 25 frequency events) is sufficient to stabilize the result and alleviate the perceived problem associated with outliers in the measurement of Balancing Authority Frequency Response performance.

Measurement Methods – Median, Mean or Regression Results

All of the normalized data were analyzed using all three candidate methods for measuring FRM.

Median – Median is the numerical value separating the higher half of a one-dimensional sample, a one-dimensional population, or a one-dimensional probability distribution, from the lower half. The Median of a finite list of numbers is found by arranging all the observations from lowest value to highest value and picking the middle one. When the number of observations is even, there is no single middle value; the Median is arbitrarily defined as the mean of the two middle values.

In a sample of data, or a finite population, there may be no member of the sample whose value is identical to the Median (in the case of an even sample size), and, if there is such a member, there may be more than one so that the Median may not uniquely identify a sample member. Nonetheless, the value of the Median is uniquely determined with the usual definition. A Median is also a central point that minimizes the arithmetic mean of the absolute deviations. However, a Median need not be uniquely defined. Where exactly one Median exists, statisticians speak of "the Median" correctly; even when no unique Median exists, some statisticians speak of "the Median" informally.

The Median can be used as a measure of location when a distribution is skewed, when end-values are not known, or when one requires reduced importance to be attached to outliers, e.g., because they may be measurement errors. A Median-unbiased estimator minimizes the risk with respect to the absolute-deviation loss function, as observed by Laplace.[45] For continuous probability distributions, the difference between the Median and the Mean is never more than one standard deviation. Calculation of Medians is a popular technique in summary statistics and summarizing statistical data, since it is simple to understand and easy to calculate, while also giving a measure that is more robust in the presence of outlier values than is the Mean.

Mean – Mean is the numerical average of a one-dimensional sample, a one-dimensional population, or a one-dimensional probability distribution. A Mean-unbiased estimator minimizes the risk (expected loss or estimate error) with respect to the squared-error loss function, as observed by Gauss.[46] The Mean is more sensitive to outliers for the very reason that it is a better estimator; it minimizes the squared-error loss function.

Linear Regression – Linear Regression is the linear average of a multi-dimensional sample, or a multi-dimensional population. A Linear Regression-unbiased estimator minimizes the risk (expected loss or estimate error) with respect to the squared-error loss function in multiple dimensions, as observed by Gauss.[47] The Linear Regression is also sensitive to outliers for the very reason that it is a better estimator; it minimizes the squared-error loss function.

Important Considerations

The following issues are important to consider with respect to the selection of the best method for measuring Frequency Response.

Two-Dimensional Measurement – Two-dimensional measurement of Frequency Response provides the best representation of the change in MWs divided by the change in frequency and is used to estimate the Frequency Bias Setting which indicates the Frequency Response in MWs provided at actual frequency as compared to scheduled frequency.

Non-linear Attribute of Frequency Response – The Non-linear attribute of Frequency Response has been demonstrated on all of the North American interconnections and is an important consideration in the representation of Frequency Response.

A Single Best Estimator – A single best estimator of Frequency Response is a necessary result for use in compliance evaluation.

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45 An absolute-deviation loss function is used to minimize the risk of estimate error when dealing with uniform distributions. Appendix 3 provides a description of Uniform Distributions and a derivation of the Median.

46 A squared-error loss function is used to minimize the risk when dealing with normal (Gaussian) distributions. Appendix 4 provides a description of normal (Gaussian) distributions and a derivation of the Mean.

47 Appendix H provides a derivation of the Linear Regression.

Linear System – A linear system[48] is assumed in the development of the individual Frequency Response Obligation for each Balancing Authority on a multiple Balancing Authority interconnection and is used to distribute the Interconnection Frequency Response Obligation among the Balancing Authorities on that interconnection. If the system within which it has been developed and measured is a Non-linear System,[49] then the conclusion that, "If all Balancing Authorities provide their Frequency Response Obligation, the interconnection will achieve its total required frequency Response cannot be logically concluded.

Bi-Modal Distributions – Bi-modal distributions occur whenever a reconfiguration of Balancing Authorities occurs within a compliance year. Unless the method chosen can correctly represent bi-modal distributions, reconfigured Balancing Authorities cannot be effectively measured for compliance.

Quality Statistics – Quality statistics should be available for use in compliance evaluation. The measure of Frequency Response is used to determine compliance with minimum provision of the Balancing Authorities obligation for providing its share of Frequency Response for the interconnection. Using a measure for compliance includes with it the responsibility of assuring that the measure also provides a reasonable level of confidence that it is a fair representation of the BA's performance. There is still a presumption that an indication of non-compliance should not occur due to pure chance.

Reducing Influence of Noise – Reducing influence of noise in the data is considered an important attribute in the measurement method. All measurements of Frequency Response will be affected by noise in the measurement process.

Reducing Influence of Outliers – Reducing influence of outliers in the data is considered the most important attribute in the measurement method. All measurements of Frequency Response will be affected by true outliers. The risk associated with the reduction in the influence of outliers is that valid information about the measure is also lost when an outlier reduction method is used.

Ease of Calculation Familiar Indicator – Ease of calculation and familiar indicators are important considerations for communication and to promote ease of understanding by the industry.

Appendix H presents the series of graphs indicating results for each Balancing Authority. Each graph shows all of the individual data points use to determine the median, mean and regression lines.

The median line is green, the mean line is blue and the regression line is red. The value of the Normalized Frequency Response (vertical axis) where the line intercepts the value of frequency

[48] A Linear System is a system in which the sum of the parts is equal to the whole.

[49] A Non-linear System is a system in which the sum of the parts is not equal to the whole.

(horizontal axis) at a value of 0.1 Hz indicates compliance. Values above 1.0 indicate a FRM above the FRO and values below 1.0 indicate a FRM below the FRO.

Figure 36 shows an example of a Balancing Authority with a small degree of variability in the measured Frequency Response for each individual event.

Figure 36: BA with Small Degree of Variability in Measured Frequency Response

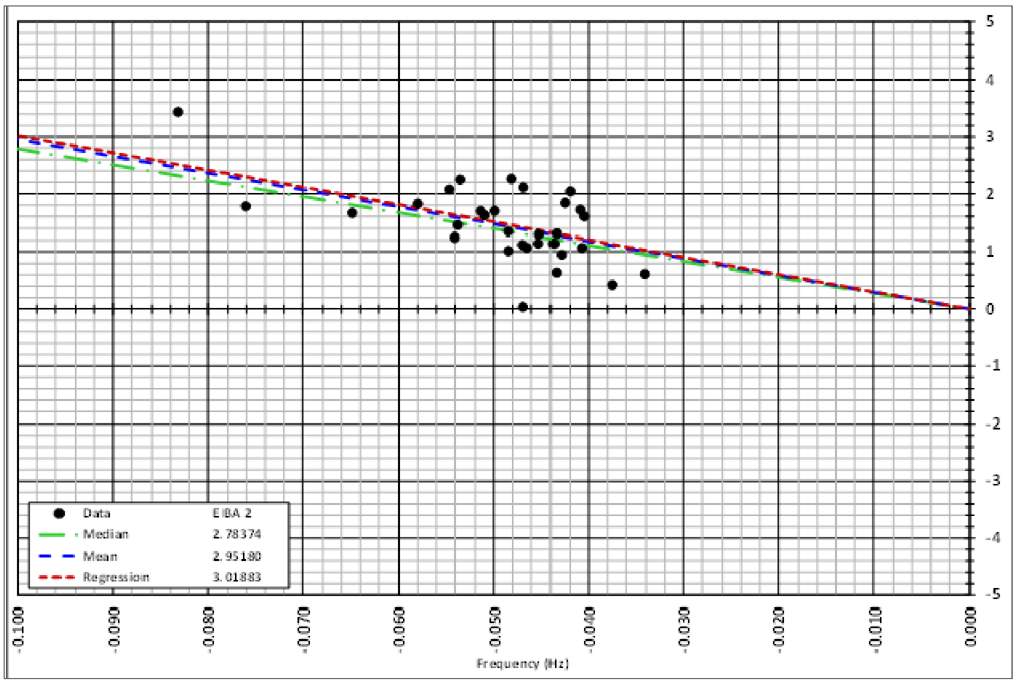
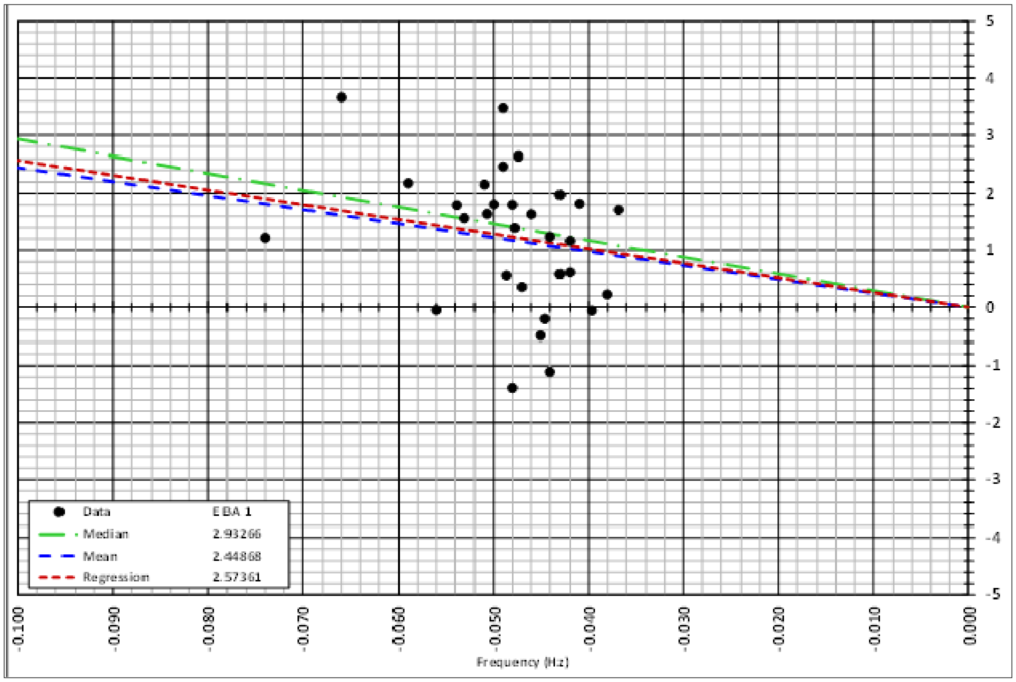


Figure 37 shows an example of a Balancing Authority with a large degree of variability in the measured Frequency Response for each individual event.

During the analysis, the graphs appeared to show that the regression provided a higher estimate of FRM than the median. Consequently, a comparison was made between the FRM as measured by the median and the FRM as measured by the regression. The results of that analysis reveal the regression shows a performance for all samples that is 0.087% of their FRO higher than is the median's performance on the Eastern Interconnection and 0.117% of their FRO higher than the median's performance on the Western Interconnection. In an unbiased analysis, one would expect the median and regression would yield the same result. Therefore, this would indicate there is some unknown statistical bias affecting the results of the analysis.

Figure 37: BA with Large Degree of Variability in Measured Frequency Response



The bias causing the difference between the median and regression results can be explained by an attribute of Frequency Response. As the frequency deviation increases for larger Disturbance events, the Frequency Response increases, but it does so disproportionately, shown in Figure M3. This attribute of Frequency Response has been demonstrated in technical papers.[50] It has also been implemented in the variable Frequency Bias Settings used by ERCOT, BPA and BC Hydro. In simple terms, the regression includes the effect of this non-linear attribute and the median does not.

The regression accommodates the disproportionality on the slope of the regression line. In this case the effect tends to be upward—ever bigger MWs per increment in size of larger frequency error. The median is biased against any disproportionate increase in response per increase in size of frequency error as part of the median's blindness to outliers. The median will give no credit for the ever-growing amount of MWs deployed per added increment in size of frequency error. All the median does is count the number of MW responses regardless of size and, to represent all the MW responses, it chooses the one that occurred half-way in the sequence of decreasingly negative and increasingly positive frequency errors. As a consequence, the median underestimates the FRM because it cannot evaluate the non-linear attribute correctly. It doesn't see or notice that attribute at all through its blinders exclusively of numerical order or placement in a sequence. Regression is the only measurement method that captures the non-linear Frequency Response correctly.

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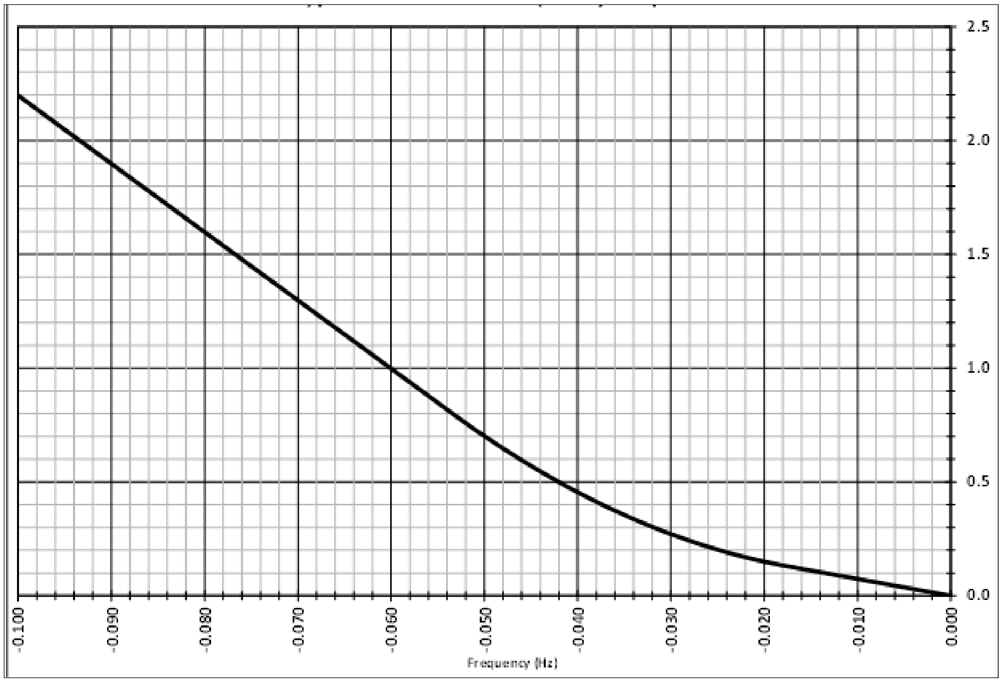
[50] Hoffman, Stephen P., Frequency Response Characteristic Study for ComEd and the Eastern Interconnection, Proceedings of the American Power Conference, 1997. Kennedy, T., Hoyt, S. M., Abell, C. F., Variable, Non-linear Tie-line Frequency Bias for Interconnected Systems Control, IEEE Transactions on Power Systems, Vol. 3, No. 3, August 1988.

Figure 38: Typical Non-Linear Frequency Response



The advantages of each method of measurement are presented in Table 18 – Median, Mean & Regression Comparison. The alphabetic key is below.

Table 18: Median, Mean, and Regression Comparison			
Attribute	Median	Mean	Regression
Provides two dimensional measurement	A	A	Yes
Represents non-linear attributes	B	B	Yes
Provides a single best estimator (single value)	C	Yes	Yes
Is part of a linear system		Yes	Yes
Represents bi-modal distributions	D	Yes	Yes
Quality statistics available	E	Yes	Yes
Reducing influence of noise	Yes (F)		Partial (G)
Reducing influence of outliers	Yes		Partial (H)
Easy to calculate	Yes	Yes	I
Familiar indicator	Yes	Yes (J)	No
Currently used as the measure in BAL-003	No	Yes	No

A. Neither Median nor Mean can evaluate the two dimensional nature of Frequency Response.

B. Neither Median nor Mean can capture the Non-linear attribute of Frequency Response and both underestimate the typical non-linear Frequency Response.

C. Median is arbitrarily defined as the average of the two central values when there is an even number of values in the data set. The decision to further constrain this central range of values to a single value that is the average of the ends of that range is unsupported by any mathematical construct. It is only the desire of those looking for simplicity in the result that supports this singular definition of Median.

D. The Median fails to provide a valid estimate of Frequency Response when the distribution of frequency event responses is bi-modal due to Balancing Authority reconfiguration or changes in responsibility for control such as partial period Overlap of Supplemental Control.

E. The Median fails to provide any methods to determine the quality, significance or confidence associated with the measure.

F. The Median reduces the influence of noise in the data, but that noise reduction comes with the cost of eliminating the availability of any quality statistics.

G. Linear Regression provides a result that weights the data according to the change in frequency. Since the noise in the data is independent of change in frequency, Linear Regression provides a superior method for reducing the influence of noise in the resulting estimate of Frequency Response.

H. Linear Regression is less sensitive to outliers and large data errors than the Mean.

I. Linear Regression is more complex and requires more effort to calculate, but that additional effort is small when the evaluation process has been automated.

J. Mean is currently used as the measure in the proposed draft BAL-003 standard.

After consideration of the mitigating effects of the sample size with respect to outliers, the linear regression method is the preferred method for calculating the Frequency response Measure (FRM) for Balancing Authorities for compliance with proposed Standard BAL-003 – Frequency Response.

Recommendation – Linear Regression is the method that should be used for calculating Balancing Authority Frequency Response Measure (FRM) for compliance with Standard BAL-003 – Frequency Response.

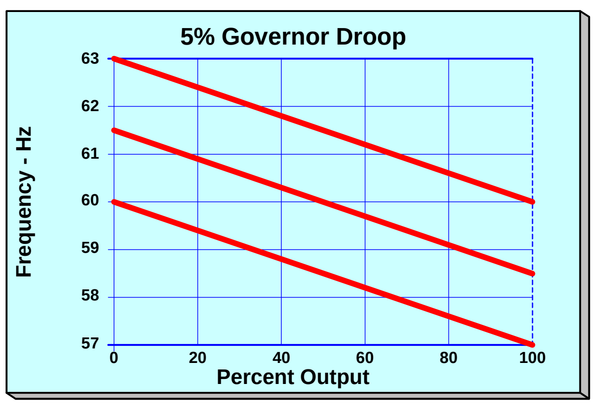
Role of Governors

Deadband and Droop

Turbine-generator units use turbine speed control systems, called governors, to control shaft speed by sensing turbine shaft speed deviations and initiating adjustments to the mechanical input power to the turbine. This control action results in a shaft speed change (increase or decrease). Since turbine generators rotate at a variety of speeds, outside the power plant it is more appropriate to generally relate shaft speed to system frequency and throttle valve position to generator output power (MW).

The expected response of a turbine-generators governor to frequency deviations is often plotted on what is known as a governor droop characteristic curve or a droop curve. The curve shows the relationship between the generator output and system frequency. The curve droops from left to right. Simply stated, as the frequency decreases, the generator's output will increase in accordance with its size.

Figure 39: Sample Droop Characteristic Curve



Droop settings on governors are necessary to enable multiple generators to operate in parallel while on governor control while not competing with each other for load changes. Droop is expressed as a percentage of the frequency change required for a governor to move a unit from no-load to full-load or from full-load to no-load. Prior to 2004, NERC Policy 1 recommended generators with governor control (typically 10 MW and larger) to have a droop setting of 5%for steam turbine (and 4% for combustion turbines, although not explicitly stated in the policy). This means that a 3 Hz (5% of 60.00 Hz) change in system frequency is required to move a generator across its full range. Normally governors respond only to substantial frequency deviations.

Guidelines of the 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 mHz).
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.

Within the Frequency Response Initiative, NERC is considering modifications to those parameters based on the recent advances in frequency response performance in ERCOT based on revised governor control parameters.

In 2010, NERC conducted a survey of governors status and settings through the Generator Owners and Generators Operators. The results of that survey are summarized in the Generator Governor Survey section of this report. A complete set of the summary graphics of the survey are contained in Appendix K.

ERCOT Experience

The general decline in primary frequency response in all interconnections has prompted regulatory entities to address the issue. Electric grids such as the one in Texas are especially sensitive to frequency regulation and response due to its relatively small overall interconnected capacity compared to the other interconnections. The Texas Regional Entity (Texas RE) is actively working on a regional standard for frequency regulation.

Frequency Regulation

Electric grid frequency regulation is attained by the response of the turbine governors to deviations from nominal synchronous speed, the operation of the boilers-turbine controls in response to the frequency change and the actions of the dispatching system.

Frequency regulation success for any given boiler-turbine plant depends on many factors, primarily:

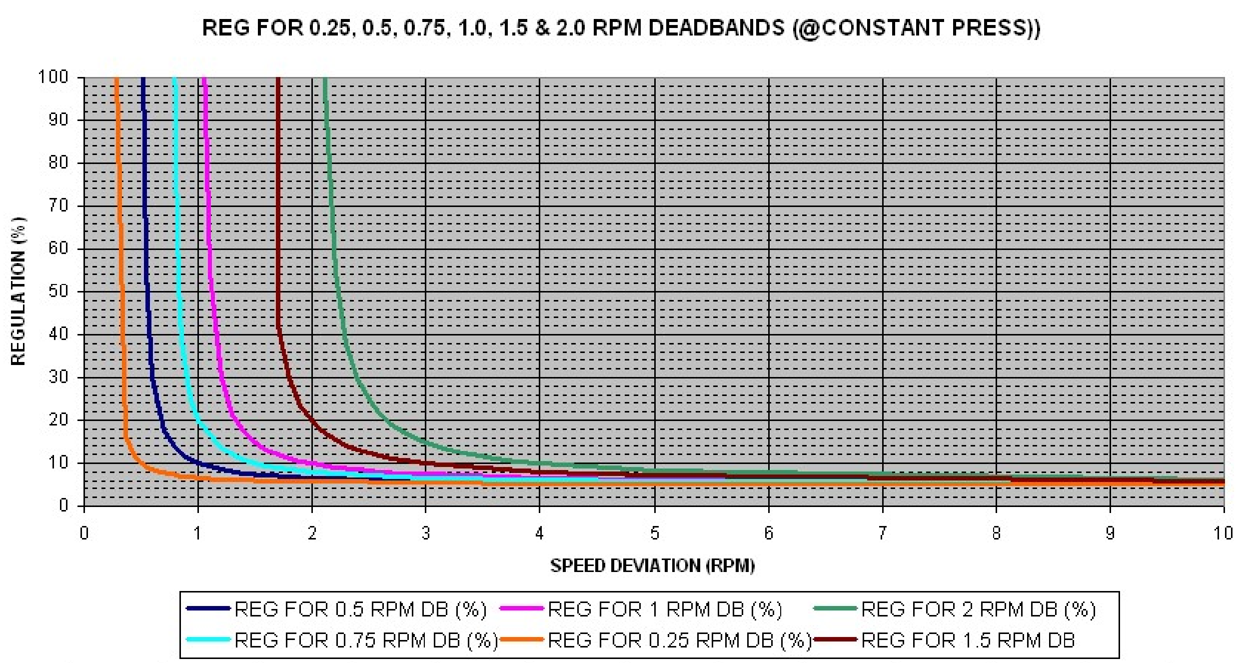
- Steady state and dynamic stability of the unit
- Load following capability
- Linearization of the turbine governor valves steam flow characteristics

- Proper calibration and coordination of the boiler and turbine frequency regulation parameters
- Proper high and low limiting of the boiler and turbine frequency regulation based on unit conditions
- Proper dispatching actions to restore the frequency to its normal operating value

Another factor that influences a unit's capability for frequency regulation is the available boiler energy storage. The larger the storage, the less the initial pressure drop caused by the quick opening of the governor valves, and the better the initial unit frequency regulation.

The standard speed regulation setting for the turbine governors of the boiler-turbine generating units is 5 percent. This is a ± 5 percent change from rated speed (0.05*3,600 = 180 RPM), causes the turbine governor to change the governor valves position demand ± 100 percent. It is also generalized industry practice to add a small deadband (DB) to the calibration of the governor speed error bias in order to minimize the movement for very small speed deviations. The selection of the DB affects the fidelity of the regulation, as shown in Figure 40.

Figure 40: Regulation versus RPM Deadbands



The regulation curves of Figure 40 are calculated by developing the equation ΔGVD= f (ΔRPM) for each DB, where ΔGVD is the change in the turbine Governor Valve Demand as a function of the change in RPM.

Knowing the ΔGVD for any given ΔRPM enables the regulation calculation via the equation:

$$REG\ (\%) = (100 * \Delta RPM / \Delta GVD)*(100/3{,}600)$$

ERCOT Nodal Operating Guides Section 2 has specific requirements for governor deadband settings. The maximum allowable deadband is ± 0.036 Hz, which has been the industry standard for mechanical "fly-ball" governors on steam turbines for many years. With the development of energy markets in the early 2000s, generators with electronic or digital governors began implementing this same deadband in their primary frequency response implementation. Unfortunately, the Guides were not clear on how to implement the droop curve at the deadband. Since the Guides required 5 percent droop performance, many generators introduced a "step function" or modified "step" once the deadband was reached in order to achieve near 5 percent droop performance outside the deadband.

As can be seen in Figure 40, a 2 rpm deadband on a 3,600 rpm turbine is equivalent to +/-0.033 Hz. Based on the corresponding droop (regulation percent) for this deadband, a generator's performance to typical frequency deviations during disturbances would be much greater than 5 percent without some "step" function. These governor settings resulted in an abnormal frequency profile for the interconnection.

Figure 41: Frequency Profile for March and September 2008
(in 5 mHz bins)

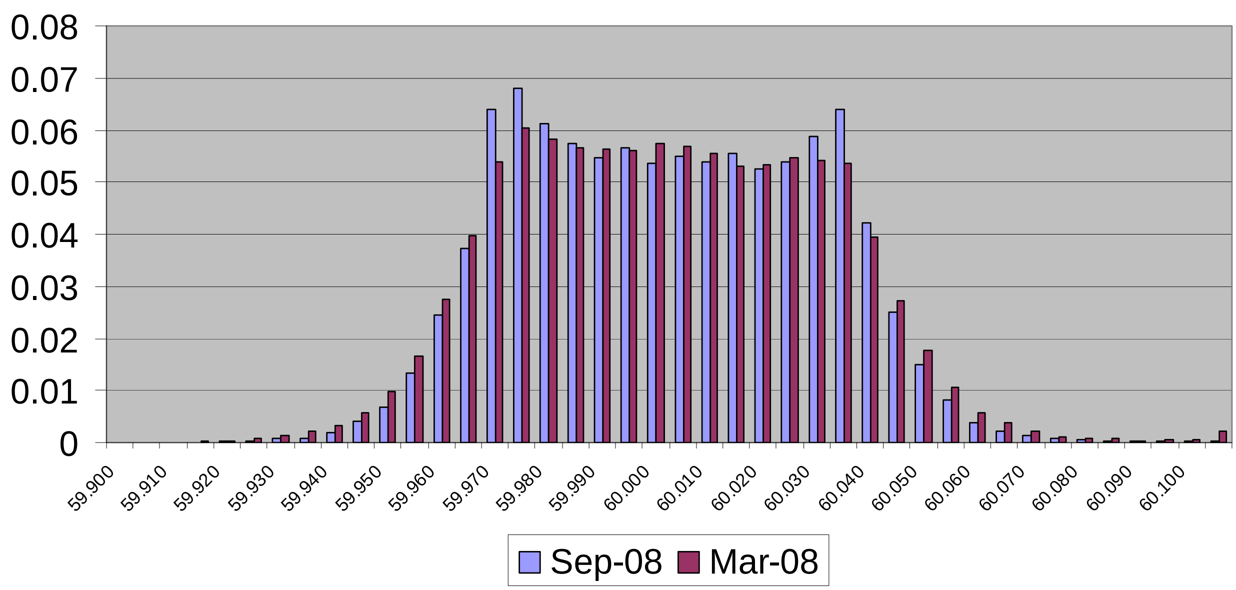


Figure 41 is the ERCOT frequency profile for March and September of 2008. It is clear that the "flat top" of the profile is centered on the ± 0.036 Hz deadband. This flat frequency profile created significant problems because frequency spent as much time at the governor deadband points as it did at any point in between. This made it difficult to employ frequency regulation to correct frequency to 60 Hz, and for ERCOT to meet the NERC CPS1 Requirement 1, since ERCOT had an epsilon-1 limit of 0.030 Hz. The frequency profile also contributed to generator instability at the deadbands with the implementation of the various "step" functions in the governors.

If generators that had implemented governor step functions were to be electrically separated from the grid during an islanding event, they would experience extreme instability. This would be caused by the governor providing excessive frequency response to the island to small generation load imbalances, resulting in large frequency swings and unit instability.

The ERCOT Performance Disturbance and Compliance Working Group (PDCWG) became increasingly concerned about the frequency instability and the realization of the risk of the step function in the governors (see Figure 42). As a result of their analysis, a member of the PDCWG discussed the issues with one large generating facility that was willing to try different deadband settings along with a specific droop curve implementation. This implementation required a straight linear curve from the deadband to full range of the governor, eliminating any step function shown in Figure 43.

Figure 42: Frequency Response of 600 MW Unit
±36.0 mHz Deadband and Step Response

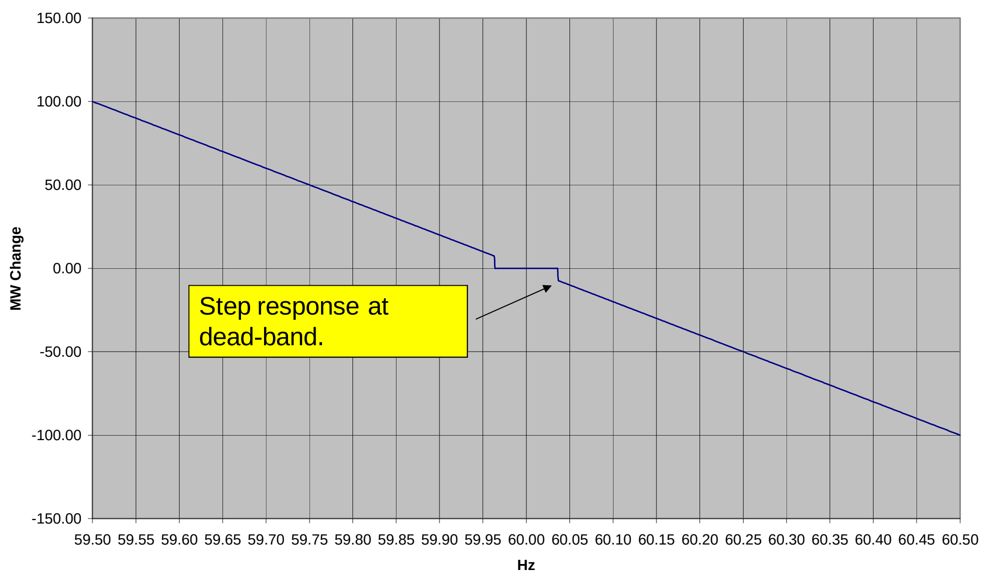
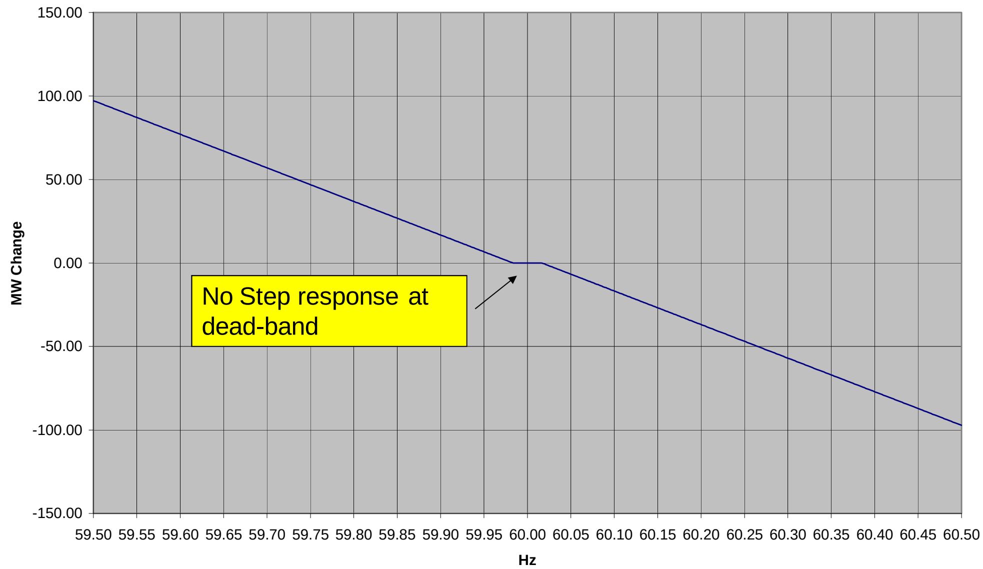


Figure 43: Frequency Response of 600 MW Unit
±16.67 mHz Deadband and No Step Response



The possibility of leaving the deadband at ± 0.036 Hz and just eliminating the stepped droop response was considered (refer to Figure 42). Analysis showed that the droop performance at 59.900 Hz would be around 7.72 percent with a ± 0.036 Hz deadband but only 5.97 percent droop with the ± 0.0166 Hz deadband. That difference increases at 59.950 Hz, with a 17.64 percent droop performance for the ± 0.036 Hz deadband and a 7.46 percent droop performance for the ± 0.0166 Hz deadband. However, without the primary frequency response of the lower deadband, the frequency profile would return to the "flat top" frequency profile spanning the ± 0.036 Hz deadbands, which is a less reliable state (less stable) for the interconnection. Also with the larger deadband, the interconnection or balancing authority may not have been able to meet the minimum frequency response requirements.

Turbine-Generator Performance with Reduced Deadbands

The general purpose for using governor deadbands is to minimize generator movement due to frequency regulation. In an interconnection where generators have various deadband settings, the diversity of settings creates diversity in responses to frequency changes. However, when a majority of the generators in an interconnection set the deadband exactly the same and with a step function, the diversity of responses disappears and frequency will move to the deadband frequently as demonstrated in the profile in Figure 43. When the frequency exceeds the deadband, all units react with a stepped response simultaneously.

The amount of generator movement expected for a specific set of deadband settings can be compared by calculating the one minute MW average movement of a hypothetical generator exposed to actual measured frequency using the different governor settings.

Table 19 compares the movement of two generators with different governor settings: one with a ± 0.036 Hz deadband and droop step function, and one with a ± 0.01666 Hz deadband and no droop step function.

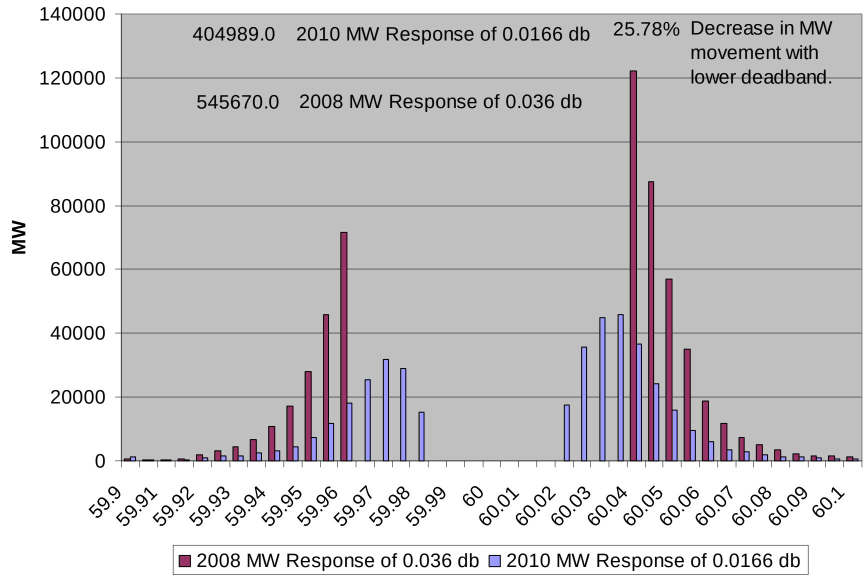
Table 19: Comparison of MW Movement for Response of Different Governor Settings			
	± 0.036 Hz Deadband with Droop Step Function	**± 0.01666 Hz Deadband with No Droop Step Function**	**Percent Increase for Smaller Deadband**
2008 Frequency Profile	662,574.0 MW-min.	893,164.2 MW-min.	34.80%
2009 Frequency Profile	446,244.0 MW-min.	692,039.8 MW-min.	55.08%

Using the 2008 one-minute average frequency data, the generator with the lower deadband would have had 893,164.2 MW-minutes of primary frequency response while the generator with the larger deadband unit would have 662,574.0 MW-minutes of primary frequency response. This is a 34.80 percent increase in movement for the lower deadband generator.

However, if the exact same comparison is made for ERCOT frequency data from 2009, where the new deadbands had an actual impact on frequency, interesting results are obtained. The lower deadband generator would have had 692,039.8 MW-minutes of primary frequency response compared to the larger deadband generator with 446,244.0 MW-minutes, a 55.08 percent increase in movement for the lower deadband. One interesting observation is that the MW-minute movement of the lower deadband generator is only 4.45 percent higher than the movement of the larger deadband generator of the previous year. (692,039.8 MW-minutes versus 662,574.0 MW-minutes).

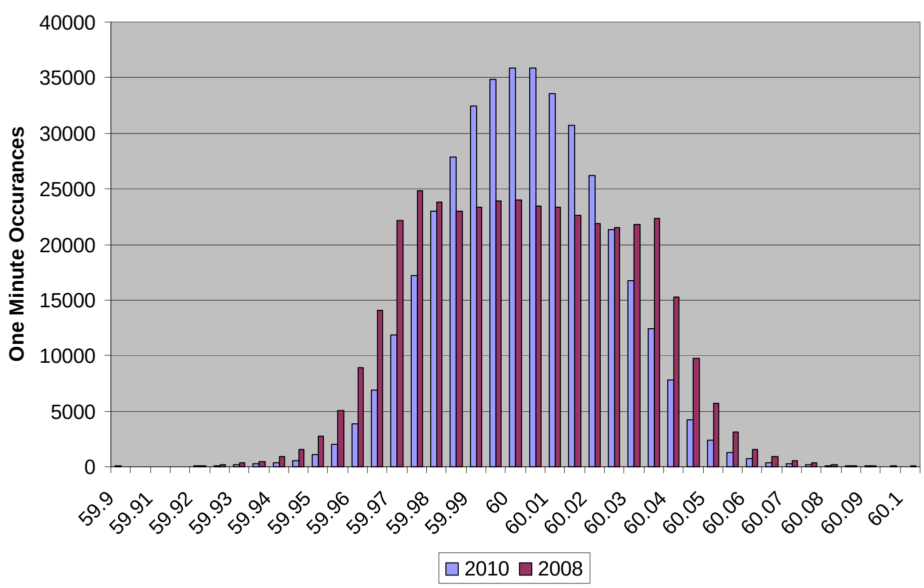
Having the lower deadband in-service for the entire year greatly reduced the frequency movement of the interconnection and reduced the primary frequency response movement as well. The lower deadband generator MW-minute movement decreased 201,124.4 MW-minutes or 22.518 percent between 2008 and 2009. This indicates the reduced impact on the generator movement with the smaller deadband and the non-step governor droop implementation when the governor becomes active as compared to the "step" implementation.

Figure 45: MW-Minute Movement of a 600 MW Unit with 5% Droop



This benefit is further emphasized by the comparison in Figure 45, which shows the response of a theoretical 600 MW unit for the 2008 ERCOT frequency profile with a ± 0.036 Hz deadband versus the same unit with a ± 0.01666 Hz deadband for the 2010 frequency profile. Using the lower deadband, there is a savings of 140,641 MW-minutes of regulation movement because there were a larger number of generators using the ± 0.01666 Hz deadband in 2010 which greatly influenced the frequency profile. Figure 46 shows a comparison of the actual January through September ERCOT frequency profiles for 2010 and 2008. The profile changed from a flat response between the ± 0.036 Hz deadband to a more normal distribution.

Figure 46: ERCOT 2010 versus 2008 Frequency Profile (Jan. – Sept.)



Conclusion – The benefits of using the smaller ± 0.01666 Hz deadband coupled with a non-step governor droop implementation results in:

- Improved frequency response for small disturbances
- Generators responding more often in smaller increments, saving fuel and wear and tear on turbines
- More stable operation when near boundary conditions of deadbands

Recommendation – NERC should embark immediately on the development of a turbine-generator governor Guideline calling for deadbands of ±16.67 mHz with droop settings of 4%-5% depending on turbine type. This effort is aimed at retaining or regaining frequency response capabilities of the existing generator fleet.

Generator Governor Survey

On September 9, 2010, NERC issued a Generator Governor Information and Setting Alert (the “Alert”) recommending that generator owners (GOs) and generator operators (GOPs) provide information and settings for generator governors for all generators rated at 20 MVA or higher, or plants that aggregate to a total of 75 MVA or greater net rating at the point of interconnection (i.e., wind farms, PV farms, etc.). The Alert was issued as a “Recommendation” to industry which requires reporting obligations, as specified in Section 810 of the Rules of Procedures, from industry to NERC and, subsequently, from NERC to the Federal Energy Regulatory Commission (FERC). Balancing authorities in North America were the only functional group required to respond to this Alert. A copy of the survey instructions is located in Appendix J of this report.

The Survey requested three types of information:

1. Policies on installation and maintenance, and testing procedures and testing frequency for governors;
2. Unit-specific characteristics and governor settings
3. Unit-specific performance information for a recent, single event

NERC sent the Survey instrument and instructions to 799 GOs and 748 GOPs in North America. Of the 794 GOs that acknowledged receipt of the Survey, 749 developed and provided a response. Of the 743 GOPs that acknowledged receipt of the Survey, 721 developed and provided a response.

Administrative Findings

NERC staff first reviewed the information submitted by the GOs and GOPs. This initial review led to the following findings from the administration of the Survey:

1. There is a wide variety of levels of understanding among GOs and GOPs of the role of generator governors in maintaining frequency response, including confusion in terminology and a lack of understanding of governor control settings. This indicates a need for education on settings and performance of generator governors, and the governor's role in interconnection frequency response.

   Recommendation – NERC should address improving the level of understanding of the role of generator governors through seminars and webinars, with educational materials available to the Generator Owners and Generator Operators on an ongoing basis.

2. There was a significant amount of duplication of reporting. This was mostly due to dual submittals by entities that are registered both as GOs and as GOPs. NERC staff sought to eliminate as much duplication as possible. However, eliminating duplication was difficult when the entities that own and operate a generator differ, yet both submitted information on the same generator. Hence, there remains some duplication in this analysis.

Summary of the Survey Responses

Table 20 summarizes, by interconnection, the aggregate characteristics of the generators analyzed.

Table 20: Number of Generators as Reported

Interconnection	Total Generators Reported	Generators Reported as Having Governors	Generators Not Having Governors
Eastern	4,372 (648.7 GW)	4,217 (630.2 GW)	152 (18.5 GW)
Western	1,560 (171.6 GW)	1,445 (162.9 GW)	114 (8.7 GW)
ERCOT	503 (95.6 GW)	446 (85.6 GW)	53 (9.0 GW)
Totals	6,435 (915.9 GW)	6,110 (878.7 GW)	319 (36.2 GW)

Figures 47 through 49 summarize the responses on generator governors for three of the interconnections. Data for the Québec Interconnection is not summarized in this report. The GOs and GOPs reported that governors were operational for 95%, 97%, and 99% of the total number of generating units that were reported as having governors in the Eastern, Western, and Texas Interconnections, respectively.

Figure 47: – Eastern Interconnection Generator Responses

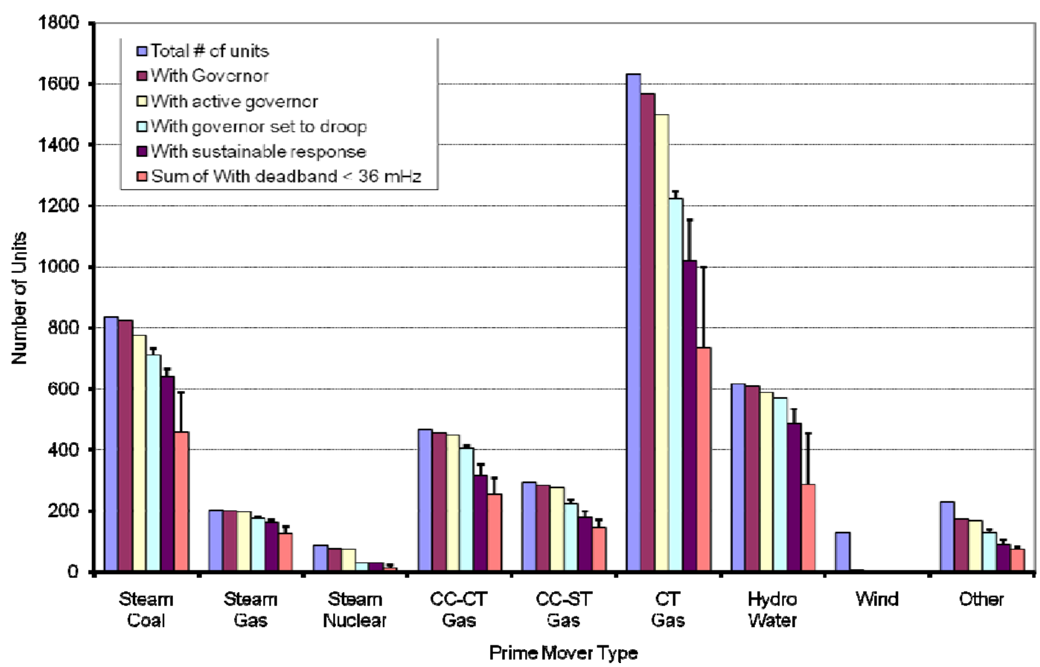


Figure 48: Western Interconnection Generator Responses

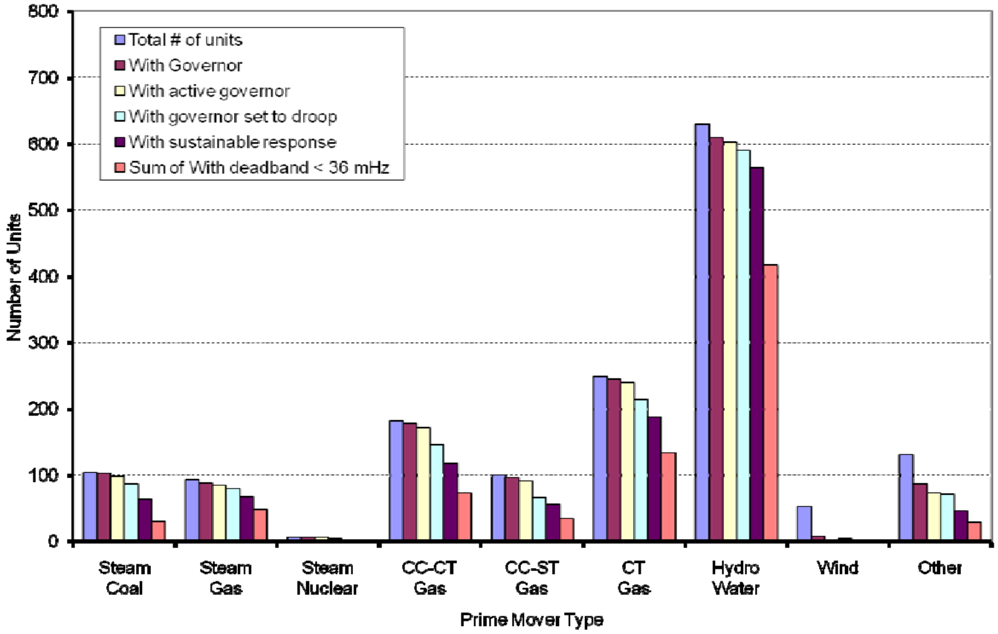
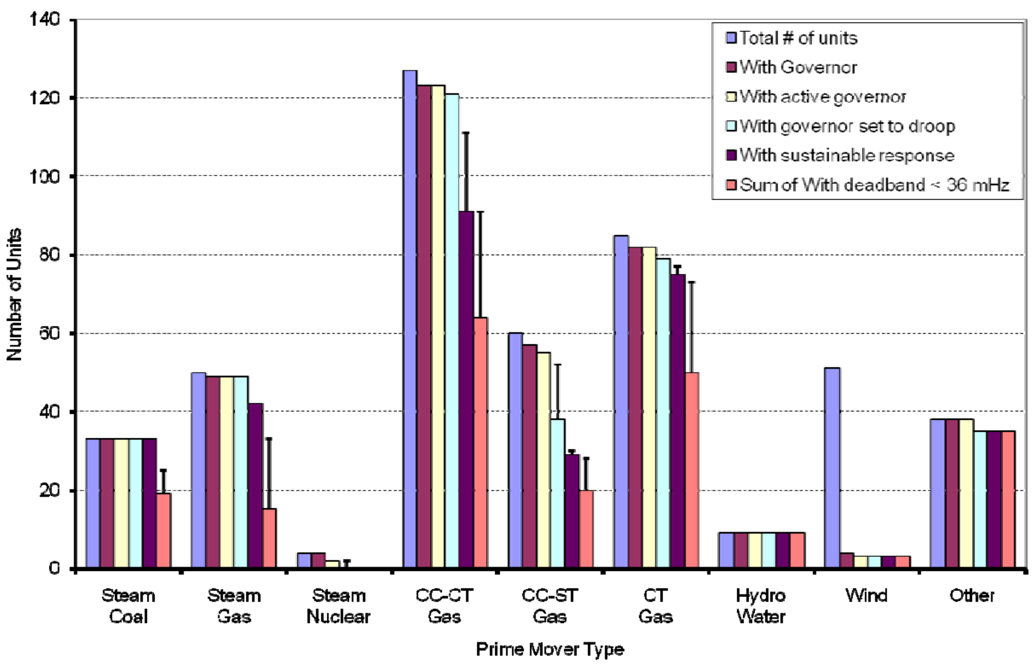


Figure 49: ERCOT Interconnection Generator Responses



Reported Deadband Settings

The deadband setting of a governor establishes a minimum frequency deviation that must be exceeded before governor will act. Frequency deviations that are less than the setting will not cause the governor to act. Of the information provided by the GOs and GOPs on governor deadbands, 51%, 63%, and 79% of the number of units in the Eastern, Western, and Texas Interconnections, respectively, was usable. Figure 50 summarizes the usability of the deadband data submitted in the survey.

Figure 50: Usability of Information Provided on Governor Deadbands

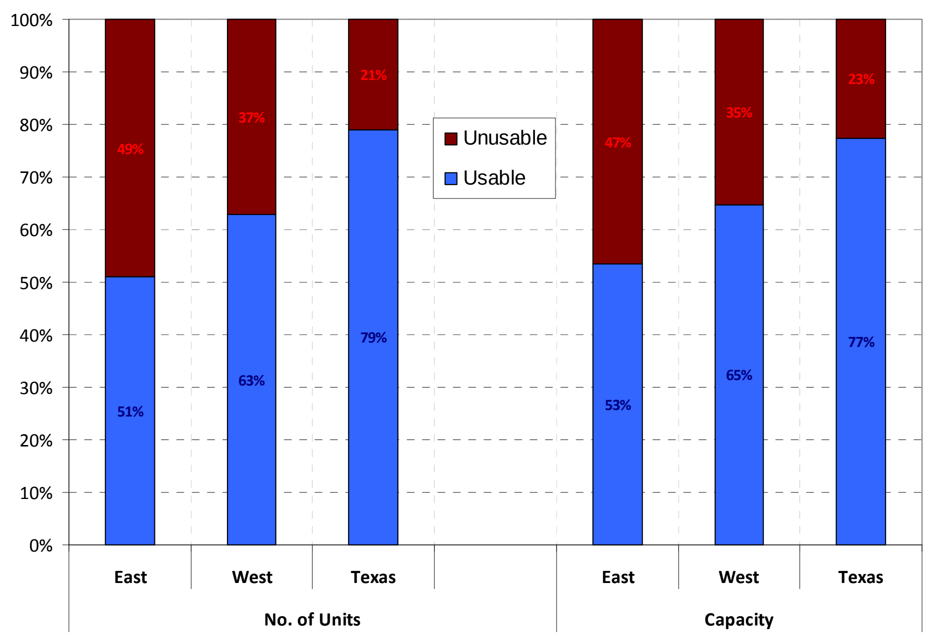


Figure 51 summarizes the range of deadband settings reported by of generating unit size for all three interconnections. The simple average, or mean, of the frequency response values calculated is indicated by the orange dot. The median of these values is indicated by a horizontal line inside the green box. The upper and lower boundaries of the box are the inter-quartile range, which is the range that contains half the calculated frequency response values. Finally, the end points of the upper and lower vertical lines indicate the lowest and highest calculated frequency response values, respectively.

The use of these descriptive statistics provides additional information on the distribution of values. For example, if the average is lower than the median, it means that the distribution has a small number of low values compared to the main body of values. Similarly, the height of the inter-quartile range (the top and bottom of the box) provides a measure of how widely the values are distributed. The location of the median within the box indicates whether values are evenly distributed on either side of the median (when the median is close to the center of the box) or whether values are disproportionately on one or the other side of the median (when the median is closer to the top or the bottom of the box).

Figure 51: Reported Governor Deadband Settings

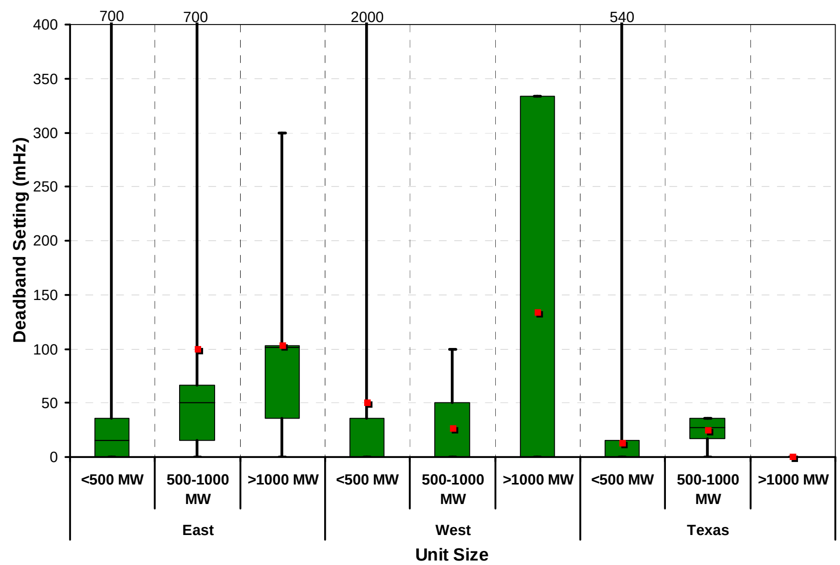


Figure 51 indicates:

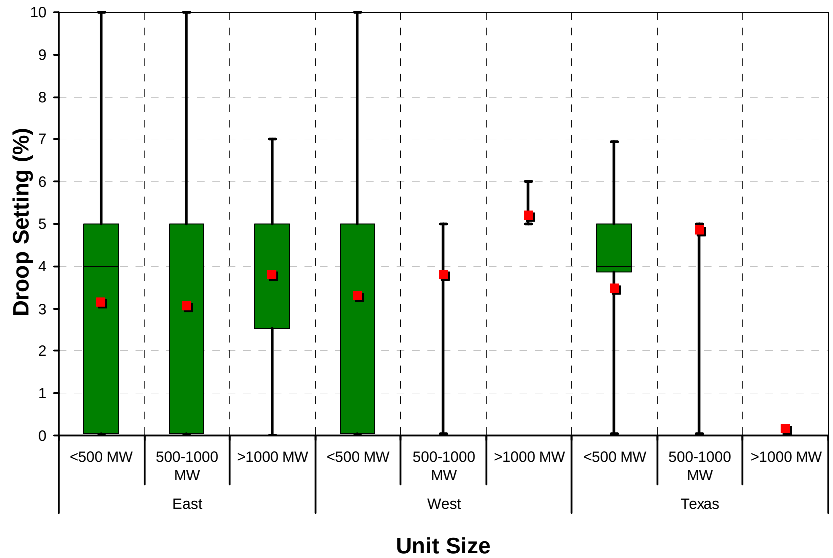
- Eastern Interconnection – Half of the dead band settings are between 0 and 100 mHz, with the smallest generating units having the lowest settings, followed by the mid-size, and then the largest units. The figure also indicates that there are a number of units in all size ranges with very high dead band settings (> 200 mHz).
- Western Interconnection – Half of the dead band settings are between 0 and 50 mHz for the smallest and mid-size generating units. However, the range is considerably broader for the largest units, with half of the settings lying between 0 and more than 300 mHz. The very large deadbands on units greater than 1,000 MW are attributable to the nuclear units.
- Texas Interconnection – The dead band settings are generally less than 50 mHz. There appears to be at least one very high dead band setting for a small generating unit.

Reported Droop Settings

Governor droop expresses the effect of changes in generating unit speed in terms of changes in power output as a function of the amount of frequency deviation from the reference frequency. Of the information provided by the GOs and GOPs on governor droop settings, 89%, 94%, and 87% of the number of units in the Eastern, Western, and Texas Interconnections, respectively, was usable.

Figure 52 summarizes the range of governor droop settings for the interconnections. Generally, the droop settings were in the range of expected values.

Figure 52: Range of Governor Droop Settings by Generating Unit Size



Governor Status and Operational Parameters

A number of the survey questions addressed the operational status and parameters of the governor fleet. As shown in Figure 53, the vast majority of the GOs and GOPs reported that their governors are operational.

Figure 54 shows that the governors also were reported to generally be able to sustain primary frequency response for longer than 1 minute if the frequency remains outside of its deadband. However, as shown in Figure 55, roughly half of the governors are expected to be overridden or limited by plant-level control schemes. This factor heavily influences the sustainability of primary Frequency Response, contributing to the withdrawal symptom often observed in the Eastern Interconnection, especially during light load periods.

Figure 53: Operational Status of Governors

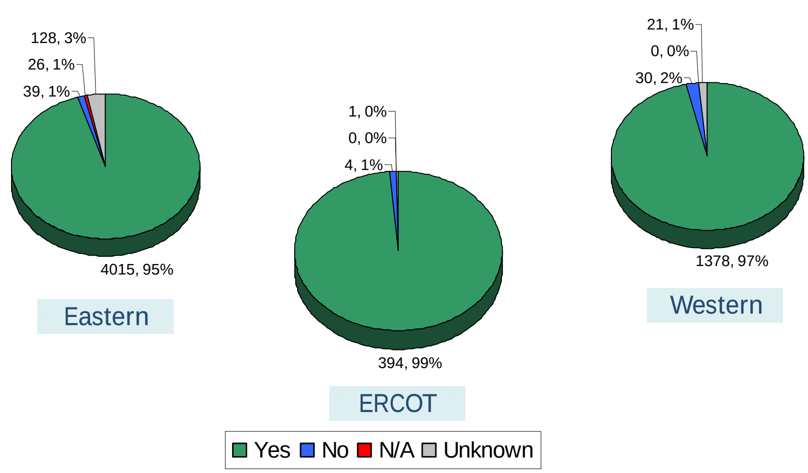


Figure 54: Response Sustainable for More Than 1 Minute if Outside Deadband

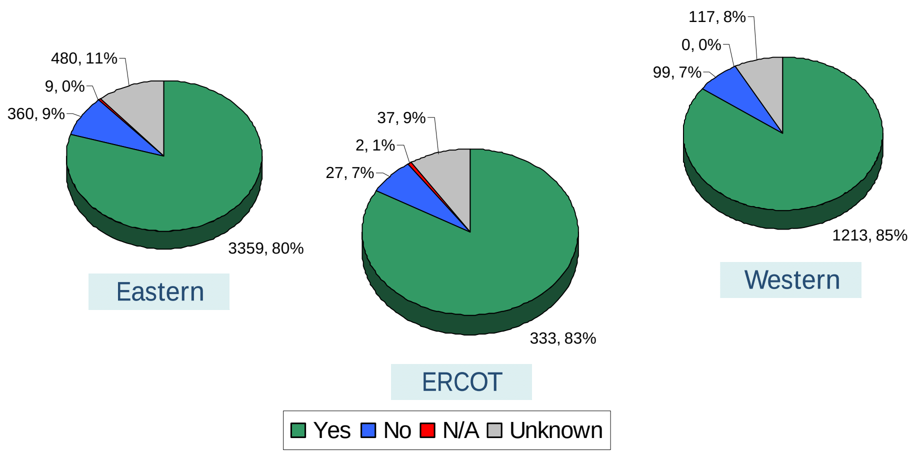
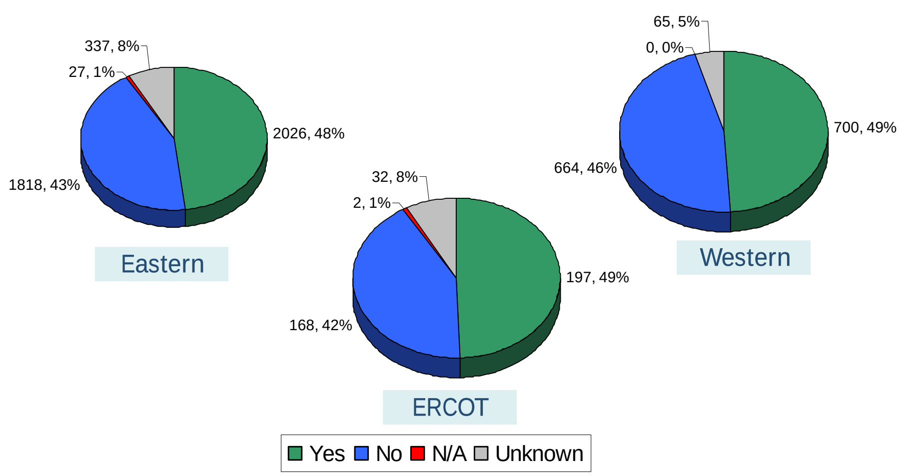


Figure 55: Unit-Level or Plant-Level Control Schemes that Override or Limit Governor Performance



Response to Selected Frequency Events

The GOs and GOPs were asked to provide information on the performance of generator governors during a selected event in each interconnection. Table 21 lists the date and time of the events selected for the Eastern, Western, and Texas Interconnections (data was not requested from the Québec Interconnection).

Table 21: Selected Events for Provision of Generator Governor Performance Information		
Interconnection	Basis	Frequency
Eastern	8/16/2010 1:06:15 CST	1,200 MW
Western	8/12/2010 14:44:03 CST	1,260 MW
ERCOT	8/20/2010 14:25:29 CST	1,320 MW

Of the interconnections' total generating capacity, 64%, 58%, and 75% of the units were on-line at the time of the event for the Eastern, Western, and Texas Interconnections, respectively.

Figure 56: Governor Response by Total Generating Capacity On-Line

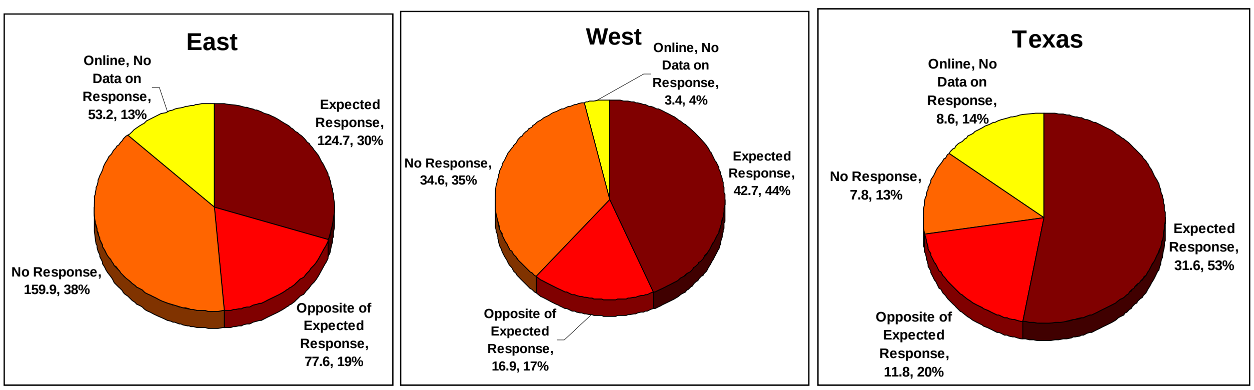


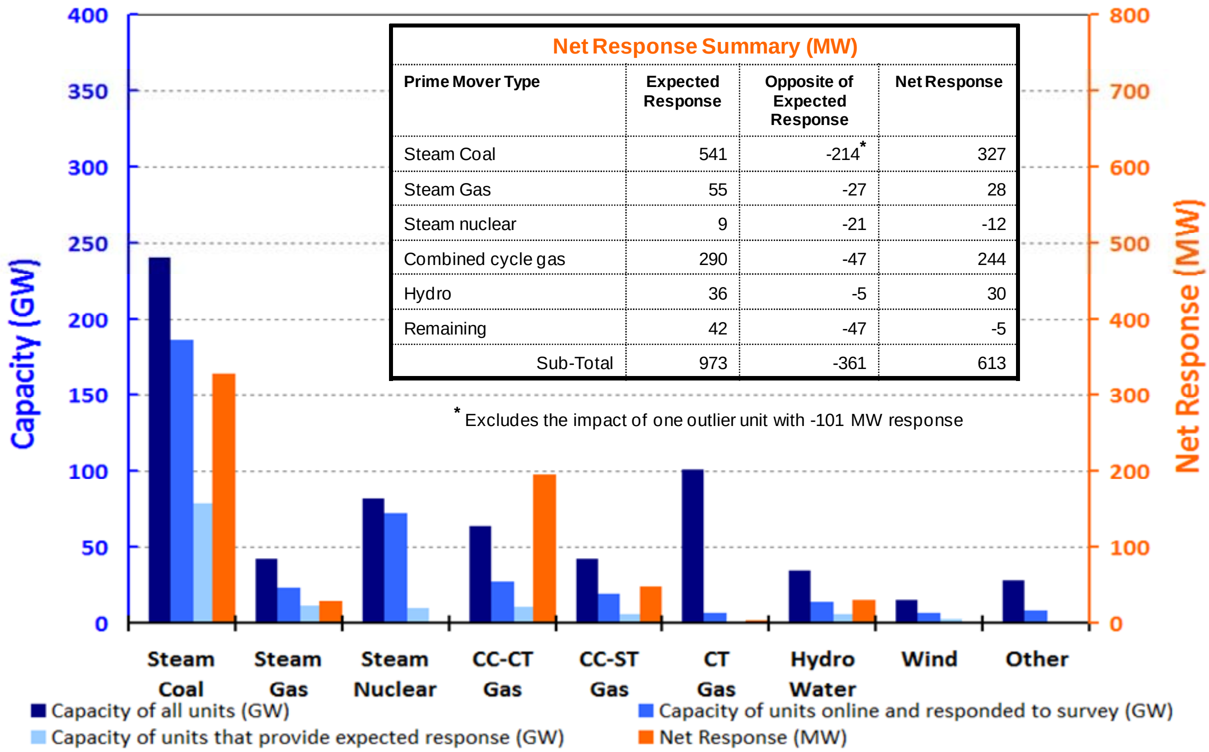
Figure 56 shows:

- Of the total generating capacity on-line, 30%, 44%, and 53% reported responding in the expected direction of response (i.e., to correct the change in frequency) for the Eastern, Western, and Texas Interconnections, respectively.
- Some generation reported no response to the frequency deviations: 38%, 35%, and 13% for the Eastern, Western, and Texas Interconnections, respectively.
- Notably, 19%, 17%, and 20% was reported as responding in the opposite direction of the expected response (i.e., not in opposition to the change in frequency) for the Eastern, Western, and Texas Interconnections, respectively.

The values reported for the eastern Interconnection for capacity providing expected response are in keeping with those calculated from the generic governor simulation of the frequency response to the August 4, 2007 Eastern Interconnection Frequency Disturbance. Those simulations showed that 30% of the capacity on line responded, and 20% of the capacity on line withdrew primary support, leaving only 10% of the capacity on line providing sustained primary Frequency Response.

Figure 57 shows that, for the Eastern Interconnection, total response in the expected direction was 973 MW, while response in the direction opposite to expectations was -361 MW, for a total net response of 613 MW. The largest contributions were made by steam coal and combined-cycle gas turbine units, accounting for 327 MW and 244 MW of the net response, respectively. These contributions were made by steam coal and combine-cycle with a total on-line generating capacity of about 180 GW steam coal and about 60 GW combined-cycle gas turbine units, of which about 80 GW and about 10 GW of capacity provided response in the expected direction respectively.

Figure 57: Eastern Interconnection Generator Governor Performance



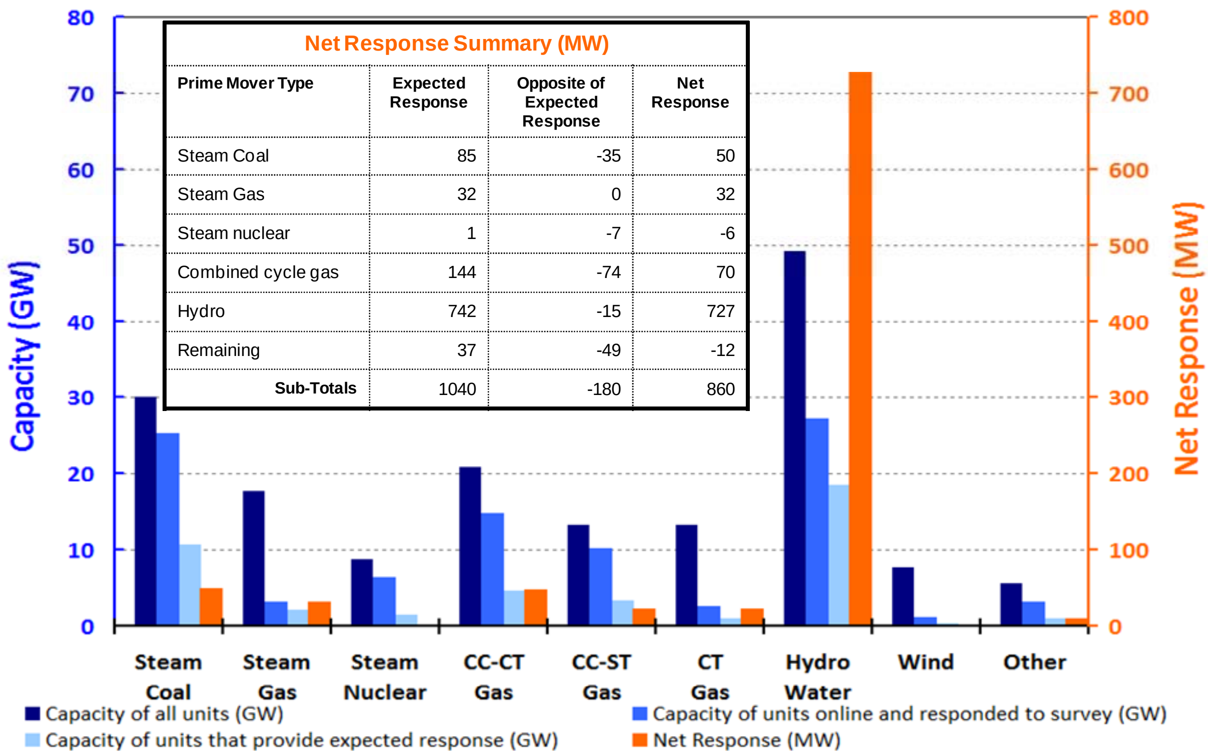
Net Response Summary (MW)

Prime Mover Type	Expected Response	Opposite of Expected Response	Net Response
Steam Coal	541	-214*	327
Steam Gas	55	-27	28
Steam nuclear	9	-21	-12
Combined cycle gas	290	-47	244
Hydro	36	-5	30
Remaining	42	-47	-5
Sub-Total	973	-361	613

* Excludes the impact of one outlier unit with -101 MW response

Figure 58 shows that, for the Western Interconnection, total response in the expected direction was 1040 MW, while response in the direction opposite to expectations was -180 MW, for a total net response of 860 MW. The largest contribution was made by hydro units, accounting for 727 MW of the net response. This contribution was made by hydro units with a total on-line generating capacity of about 50 GW, of which about 19 GW of capacity provided response in the expected direction.

Figure 58: Western Interconnection Generator Governor Performance

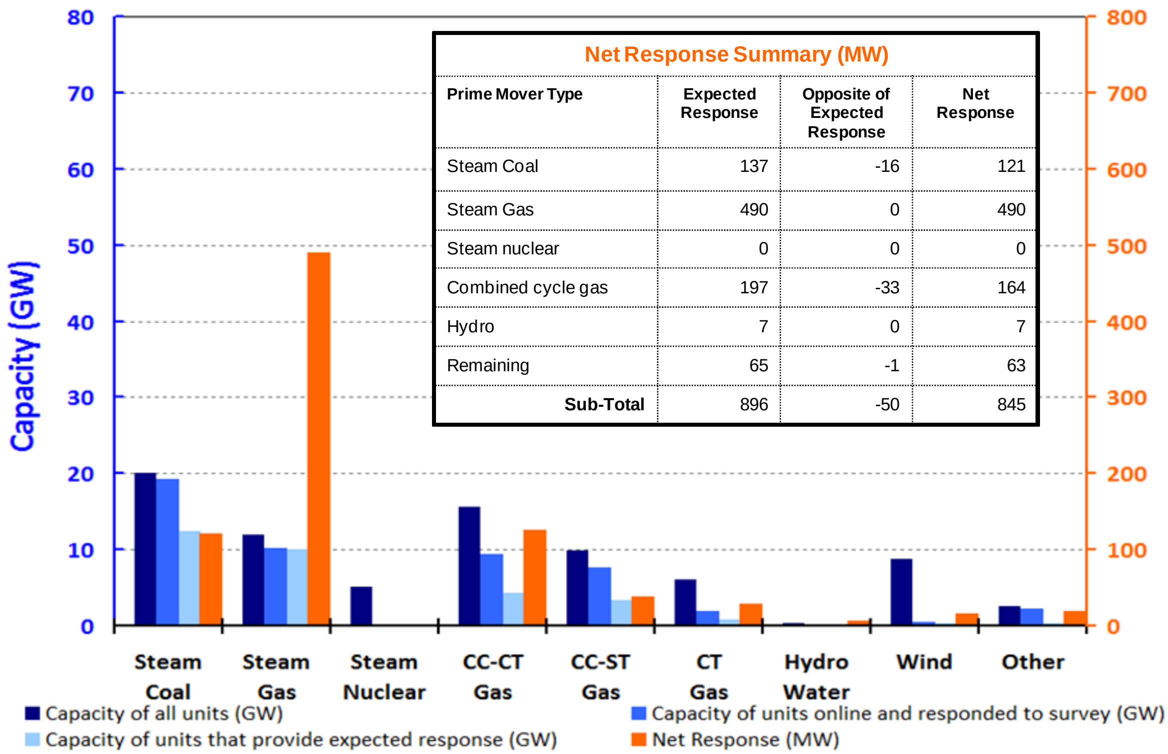


Net Response Summary (MW)

Prime Mover Type	Expected Response	Opposite of Expected Response	Net Response
Steam Coal	85	-35	50
Steam Gas	32	0	32
Steam nuclear	1	-7	-6
Combined cycle gas	144	-74	70
Hydro	742	-15	727
Remaining	37	-49	-12
Sub-Totals	1040	-180	860

Figure 59 shows that, for the Texas Interconnection, total response in the expected direction was 896 MW, while response in the direction opposite to expectations was -50 MW, for a total net response of 845 MW. The largest contribution was made by steam gas units, accounting for 490 MW of the net response. This contribution was made by steam gas units with a total on-line generating capacity of about 11 GW, of which ~10 GW of capacity provided response in the expected direction.

Figure 59: ERCOT Interconnection Generator Governor Performance



Net Response Summary (MW)

Prime Mover Type	Expected Response	Opposite of Expected Response	Net Response
Steam Coal	137	-16	121
Steam Gas	490	0	490
Steam nuclear	0	0	0
Combined cycle gas	197	-33	164
Hydro	7	0	7
Remaining	65	-1	63
Sub-Total	896	-50	845

Future Analysis Work Recommendations

Testing of Eastern Interconnection Maximum Allowable Frequency Deviations

The stability simulation testing of the Eastern Interconnection resource loss criteria used in the determination of the IFRO was limited to analysis using the generic governor stability case developed by the NERC Model Validation Working Group and the Eastern Interconnection Reliability Assessment Group (ERAG) Multi-Regional Modeling Working Group (MMWG) in December 2011 (based on the August 4, 2007 Eastern Interconnection Frequency Disturbance). Simulations using that stability simulation indicated a maximum sustainable generation loss of about 8,500 MW for the Eastern Interconnection. However, that simulation case was not for the light load conditions where system inertia and load response would be expected to be lower than in the generic case.

Recommendation – Dynamic simulation testing of the Western and ERCOT Resource Contingency Protection Criteria should be conducted as soon as possible.

Recommendation – When ERAG MMWG completes its review of generator governor modeling, a new light-load case should be developed and the resource loss criterion for the Eastern Interconnection IFRO should be re-simulated.

Eastern Interconnection inter-Area Oscillations – Potential for Large Resource Losses

During the spring of 2012, a number of inter-area oscillations were observed between the upper Midwest and the New England/New Brunswick areas in the 0.25 Hz family. During one such event, a large generation outage in Georgia instigated that oscillation mode, and was interpreted by the FNet frequency monitoring and event detection program as a 1,800 MW resource loss in the upper Midwest. Immediately, the FNet Oscillation Monitoring system detected the 0.025 Hz family oscillations between the upper Midwest and the New England/New Brunswick. Investigation into the event showed that it occurred while the Dorsey – Forbes 500 kV transmission line was out of service for maintenance. During that line outage, the transfers on the Dorsey DC line from Northern Manitoba were significantly curtailed, and the oscillation of the Dorsey DC terminal capabilities for damping the 0.025 Hz oscillations were greatly reduced. This made the system more susceptible to such oscillations. In all instances, the energy magnitude under the oscillations was small, well damped and of little danger to the reliability of the Eastern Interconnection.

However, the instigation of those oscillations by a generator trip in Georgia seemed unlikely until reviewed in light of the inter-area oscillations detected following the South Florida disturbance of February 26, 2008. During that disturbance, a family of 0.22 Hz oscillations were detected between the southeast and the upper Midwest. In both cases, the same generation in the upper Midwest has a strong participation in both mode shapes, and since both oscillation modes are close in frequency, the 0.25 Hz family was easily perturbed by an instance of the 0.22 Hz mode oscillations caused by the Georgia generator tripping.

Recommendation – Eastern Interconnection inter-area oscillatory behavior should be further investigated by NERC, including during the testing of large resource loss analysis for IFRO validation.