NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Agenda
Standard BAL-003-1 Implementation Workshop

August 23, 2016 | 9:00 a.m. – 3:00 p.m. MDT

WECC Office
Western Electricity Coordinating Council
155 North 400 West, Suite 200
Salt Lake City, UT 84103

Dial-in – 303.248.0285 | Access Code: 5247025 | Security Code: 945894
Login Information – https://cc.readytalk.com/r/dhc3kzxr99jm&eom

NERC Antitrust Compliance Guidelines and Public Announcement

Introductions & RS Chairman Opening Remarks

Agenda Items

1. **Overview of Operating Year 2015 Frequency Response Performance (Badley / Cummings)**
   a. Performance by Interconnection
   b. Discussion of key issues
2. **Changes to Forms FRS-1 and FRS-2 (Cummings)**
3. **Bias Calculations for 2017 (Cummings)**
4. **Event Reporting Problems and Solutions (Tony / Badley)**
   a. Lining up BA's frequency with event times
   b. Synchronization of tie line data for frequency events
      i. Pseudo Tie Allocations as Actual Interchange
      ii. Dynamically Scheduled Allocations as Scheduled Interchange
   c. Timing of recalculation of shares of jointly-owned-unit shares
   d. Mishandling of jointly-owned-unit shares for tripping such units with dynamic schedules
   e. Data storage and compression issues
   f. Frequency of data submittal – annual versus quarterly
5. **Mechanics of Frequency Reserve Sharing Groups – Open Discussion**
   a. Tenets of Frequency Reserve Sharing Group operations

6. **BASS Site Review (Cummings)**
   a. Access and Navigation
   b. Mechanics of submitting multiple forms

7. **Other topics (as time allows)**
   a. CPS 1 and BAAL Data Request and Submittal (Cummings)

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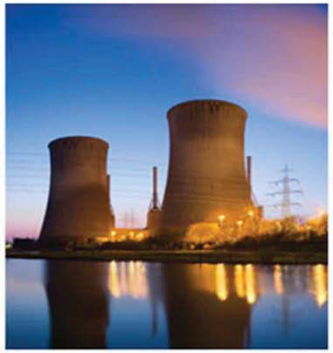
BAL-003-1 Implementation Workshop

Salt Lake City, UT

Robert W. Cummings
Senior Director of Engineering & Reliability Initiatives
August 23, 2016

RELIABILITY | ACCOUNTABILITY

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Agenda

Why Primary Frequency Response is Important

Review the History and Industry Outreach

Discuss the Identified Issues

- Dead Band
- Outer Loop Controls

Highlight Efforts Southern Company ,ISO-NE, Burns McDonnell

Frequency Response Guideline

Recommendation

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Why Primary Frequency Response Is Important

- Essential for Reliability of the Interconnections
  - Cornerstone for system stability
  - Line of defense to prevent Under Frequency Load Shedding(UFLS)
  - Prevent equipment damage
- Essential for System Restoration
  - Droop response is critical in restoration efforts
  - Hydro units and gas turbines are some of the first units to be restarted
- Compliance with NERC Standards BAL-003-1, BAL-001
  - Prevent future regulations related to generator frequency response performance
- To accurately predict system performance during disturbances (improving Transmission Models)

NERC Outreach OEM and Engineering Firms

Generator Governor Frequency Response Advisory

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Industry Advisory

Generator Governor Frequency Response

Initial Distribution: February 5, 2015

As a result of the Eastern Interconnection Frequency Initiative, the NERC Resources Subcommittee has determined that a significant portion of the Eastern Interconnection generator deadbands or governor control settings inhibit or prevent frequency response. While this specific work was based on the Eastern Interconnection, in the absence of more stringent regional requirements the following good practice and guidance is applicable to all interconnections. The proper setting of deadbands, droop, and other controls to allow for primary frequency response is essential for reliability of the Bulk Electric System (BES) and critical during system restoration. Further, the accuracy of Transmission Planning models are impacted by incorrect governor data. The purpose of this Advisory is to alert the industry of recommended governor deadband and droop settings that will enable generators to provide better frequency response to support the reliable operation of the Bulk Electric System.

Why am I receiving this? >>
About NERC Alerts >>

Status:	**No Reporting is Required – For Information Only**
	PUBLIC: No Restrictions More on handling >>
Instructions:	NERC Advisories are designed to improve reliability by disseminating critical reliability information and are made available pursuant to Rule 810 of NERC's Rules of Procedure, for such use as your organization deems appropriate. **No particular response is necessary.** This NERC Advisory is not the same as a reliability standard, and your organization will not be subject to penalties for a failure to implement this Advisory. Additionally, issuance of this Advisory does not lower or otherwise alter the requirements of any approved Reliability Standard, or excuse the prior failure to follow the practices discussed in the Advisory if such failure constitutes a violation of a Reliability Standard.
Distribution:	**Initial Distribution:** Balancing Authority, Generator Owner, Generator Operator, Reliability Coordinator, Transmission Operator, Transmission Planner Who else will get this alert? >> What are my responsibilities? >>

RELIABILITY | ACCOUNTABILITY

- Advisory issued February 5, 2015
- Initiated by NERC Resource Subcommittee
  - Interconnections frequency response has declined
  - Eastern Interconnection Lazy L profile
  - 2010 and 2013 Generator Survey Data

Generator Governor Frequency Response Advisory

Turbine OEM Reach Out to Customer Base

GE Power & Water

Product Service

Guidance to help meet NERC Frequency Response Advisory

PSIB 20150212

Info Bulletin

Overview

This bulletin addresses information to assist North American users with NERCs (North American Electric Reliability Corporation) latest guidance and industry advisory "Generator Governor Frequency response". This bulletin applies to gas turbine, gas turbine combined cycle and fossil steam plants. It does not apply to nuclear steam units. This guidance only applies to plants with an aggregate generator capability exceeding 75 MVA that observe NERCs reliability standards.

Loss of System Response

Supply and demand in bulk electric supply systems is achieved by regulating the grid frequencies in real time. Some energy is stored in the combined rotational inertia of all the synchronous generating units on the system. In the event of a generation deficit, some of this rotational energy is withdrawn and the frequency of the system will start to decline. Conversely, an excess of generation will result in frequency rising as surplus energy is converted into rotational inertia.

In order to support frequency control, it is necessary for all generation units on an interconnected system to sense changes in frequency or speed and to automatically support the system by increasing or decreasing generation to the extent that they are normally capable. This is termed as speed droop response and is intended to arrest frequency decline during a loss of generation event or frequency increase during a loss of load event. It is then the responsibility of the system operator or BA (grid balancing authority) to restore system frequency to nominal using load dispatch adjustments.

Combined rotational inertia of synchronous generation turbines and generators on

Welcome to the TIL 1961 Webinar

TIL 1961

STEAM TURBINE GOVERNOR SETTINGS TO MEET NERC FREQUENCY RESPONSE ADVISORY - Webinar: June 30, 2015 and July 01, 2015

Jim Bridgens
jim.bridgens@ge.com

Imagination at work.

GE Proprietary Information

Distributed Control System
Customer Reference 2015-001

Instrumentation, Controls & Electrical

SIEMENS

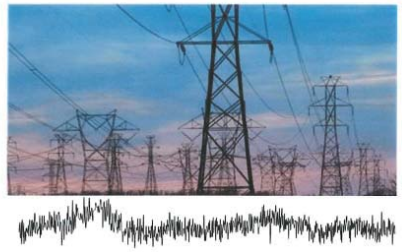
Grid Primary Frequency Control a NERC Concern. An Advisory Document in Support of an Upcoming NERC advisory

Revision 1

Effective as of: 2015-02-02

Power Generation

Application Guide – Utility - Combine Cycle Generator Governor Frequency Control



INTRODUCTION

Frequency Response is a measure of an interconnection's ability to stabilize frequency immediately following the sudden loss of generation or load. Moreover, grid stability is a function of matching power generation with the required electric load. As the electric load varies, generation must adjust to ensure that the grid's frequency is stable at 60 Hz. What happens when the grid frequency is unstable, you ask? Picture rolling blackouts and unpredictable outages.

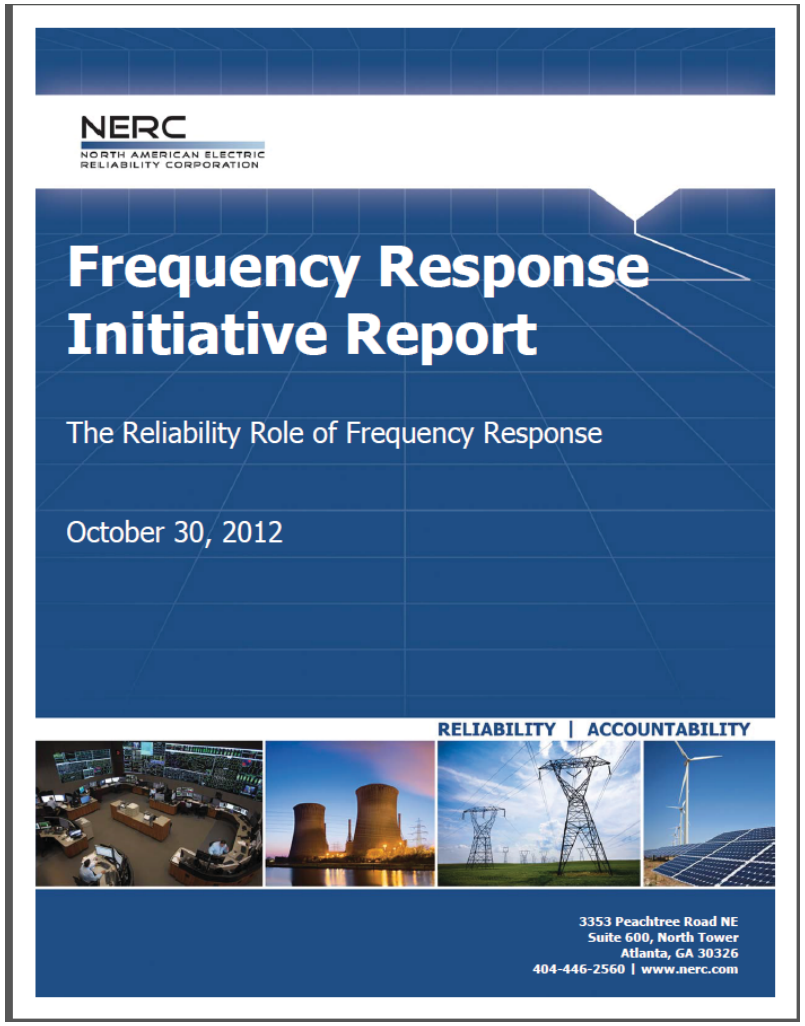
ABB supplies both boiler and combustion/steam turbine control systems to the power generation industry and frequency response have long been part of ABB's control strategy. This application guide discusses ABB's frequency control strategy that solves the primary frequency response withdraw problems and when proper tuned operates in accordance with NERC's desired response.

Doc No.:

Power and productivity for a better world™

ABB

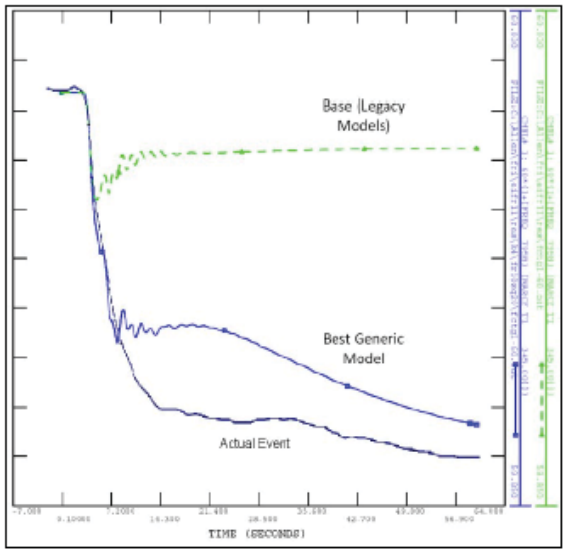
2012 Frequency Response Initiative Report



The characteristics found in that study were:

- Only 30% of the units on-line provide primary frequency response.
- Two-thirds of the units that did respond exhibit withdrawal of primary frequency response.
- Only 10% of units on-line sustain primary frequency response.

Figure 24: Comparison of Legacy and Generic Simulations to August 4 Event



Page 37, Frequency Response Initiative Report, October 2012

What is the Reliability Issue

Majority of generators in BA's fleet/ East and West Interconnections are currently incapable of providing primary frequency responsive and we continue to commission new generation and the trend continues.

Houston We Have a Problem
Audio

Problems

1) *System Restoration Plans are challenged*
2) *Transmissions Stability and other models assume generators are capable of response*
3) *BA's get a significant portion of frequency from load and can not predict the load response or control it.*

What has been learned - Deadbands exceed

Many Dead Bands Exceed 36 mHz

Primary Frequency Response logic typically resides in the turbine controls.

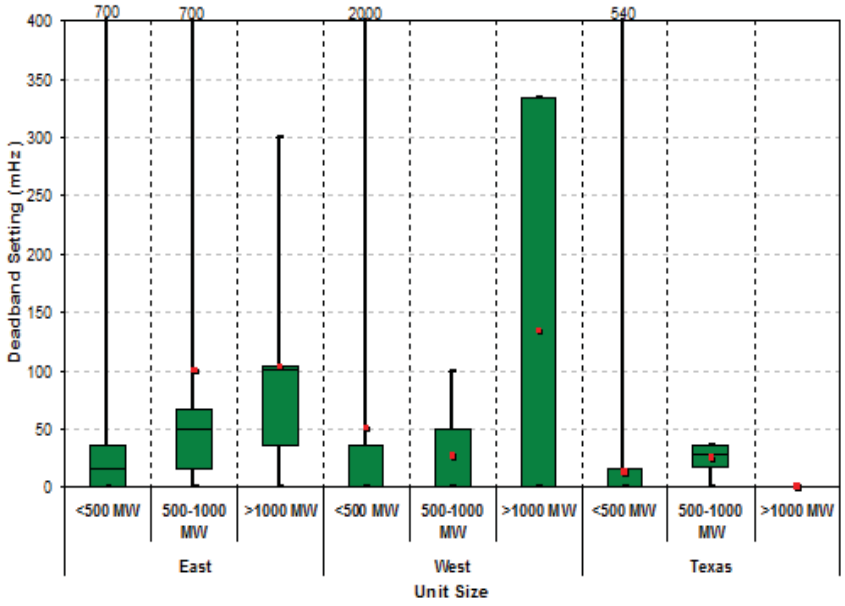
Dead Bands Vary

- *Many exceed 36 mHz or 2.16 RPM (on a 3,600 RPM machine)*

Droops Settings Vary

- *Majority Droops reported 5%*

Figure 29: Reported Governor Deadband Settings



NERC Frequency Response Initiative Report - August 2012, Bob Cummings

What has been learned – Outer Loop Control

Coordination with plant DCS is a requirement when operating in MW Set Point Coordinated Control.

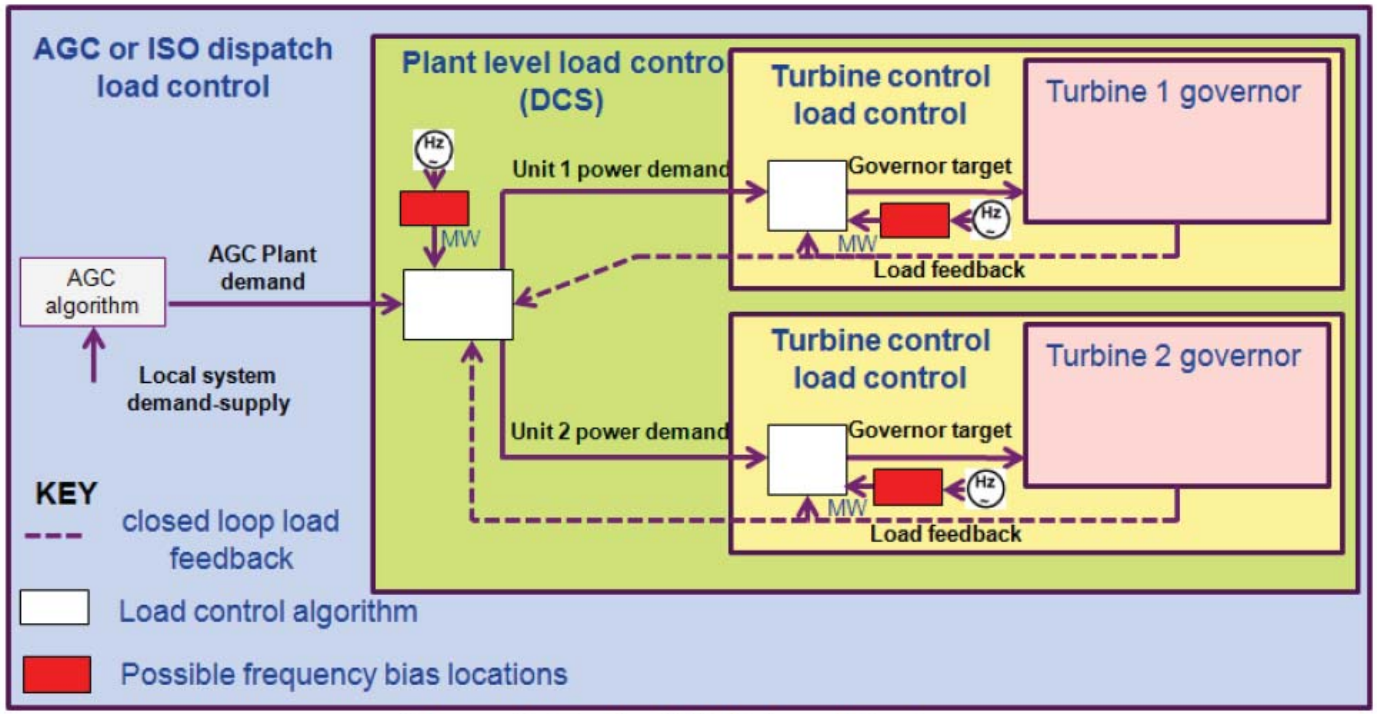
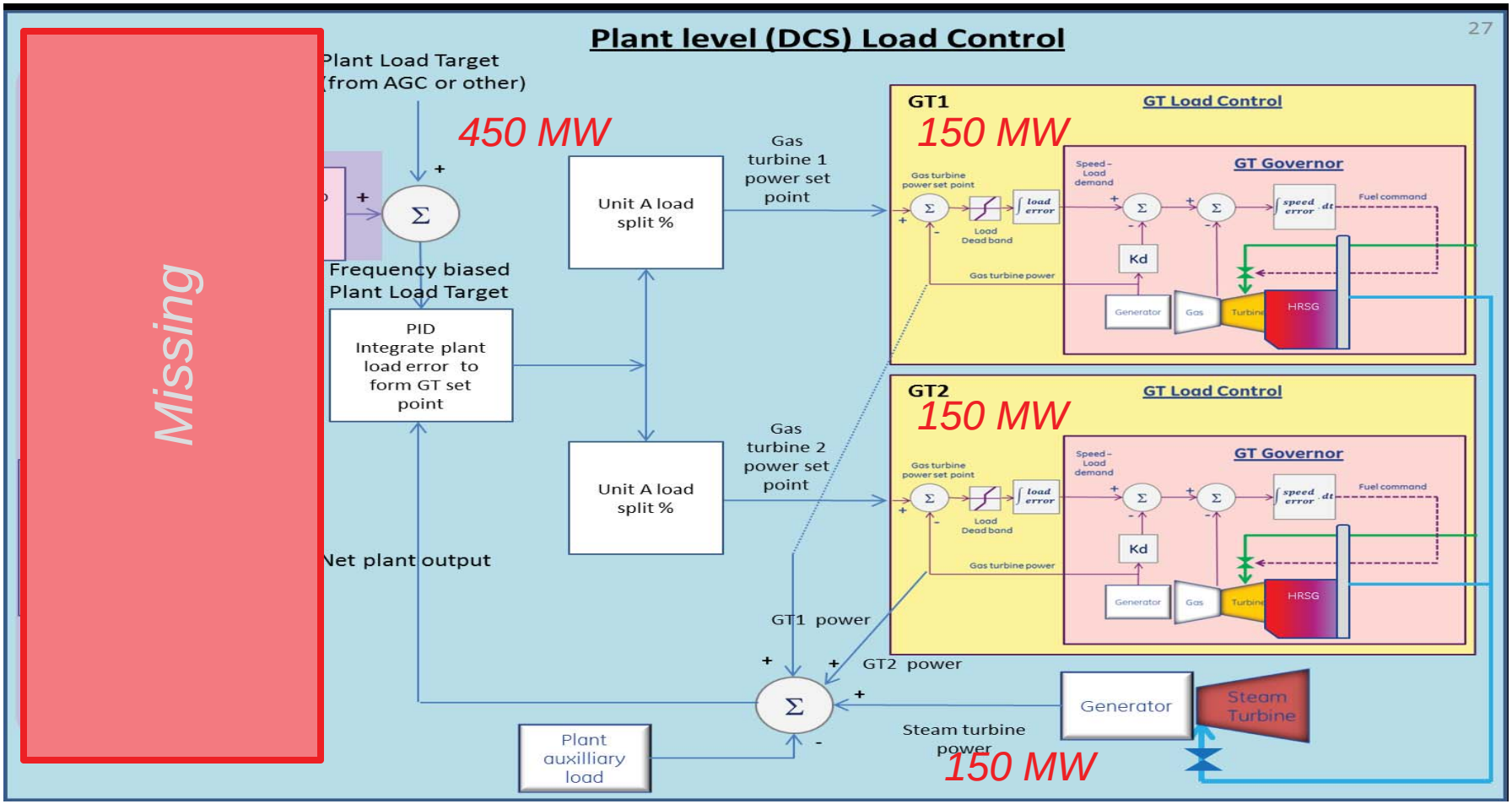


Figure 1: Typical High Level System

Illustration

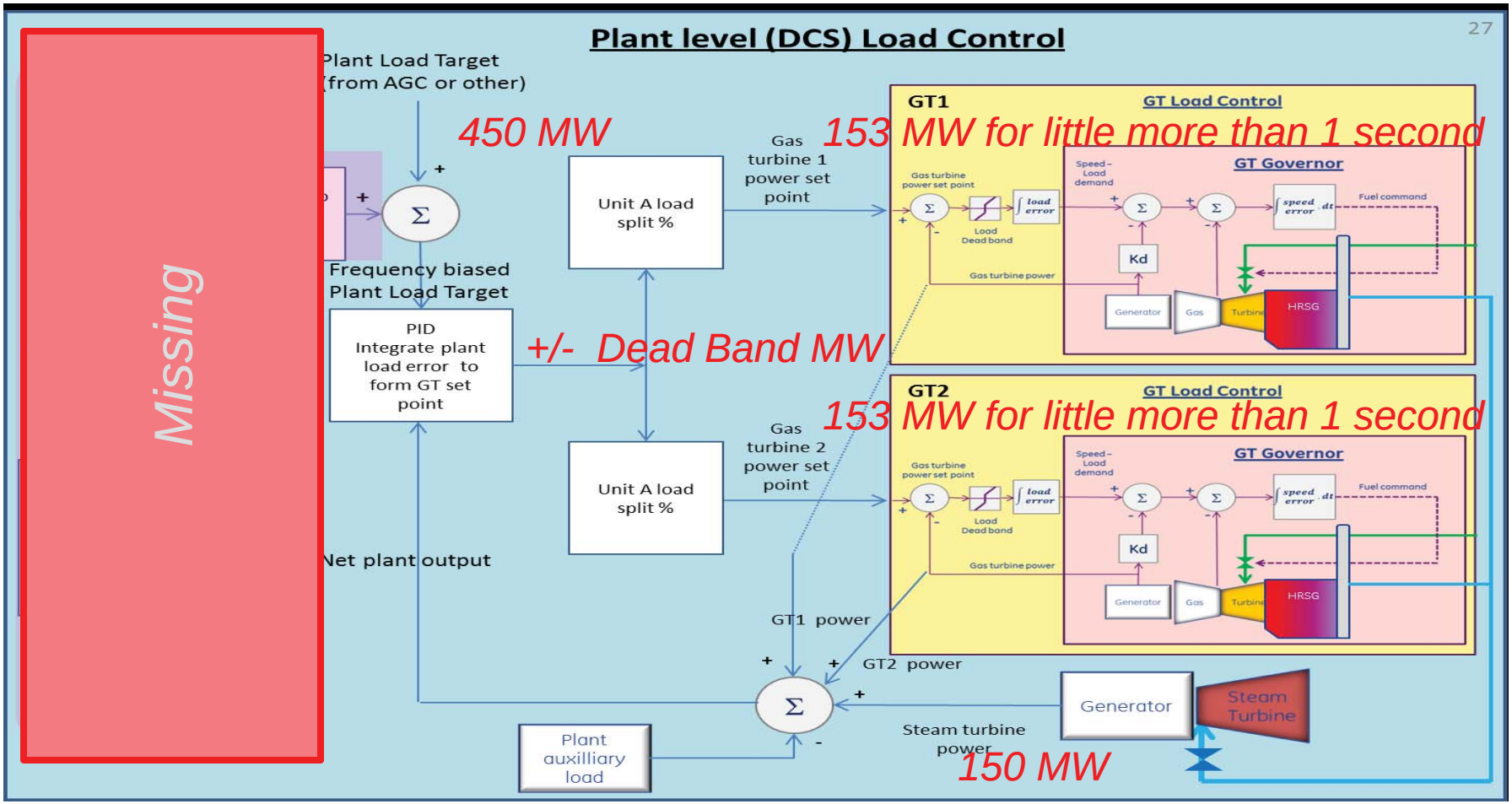
Frequency 60.000 Hz



Graphic from GE info bulletin PSIB20150212

Illustration

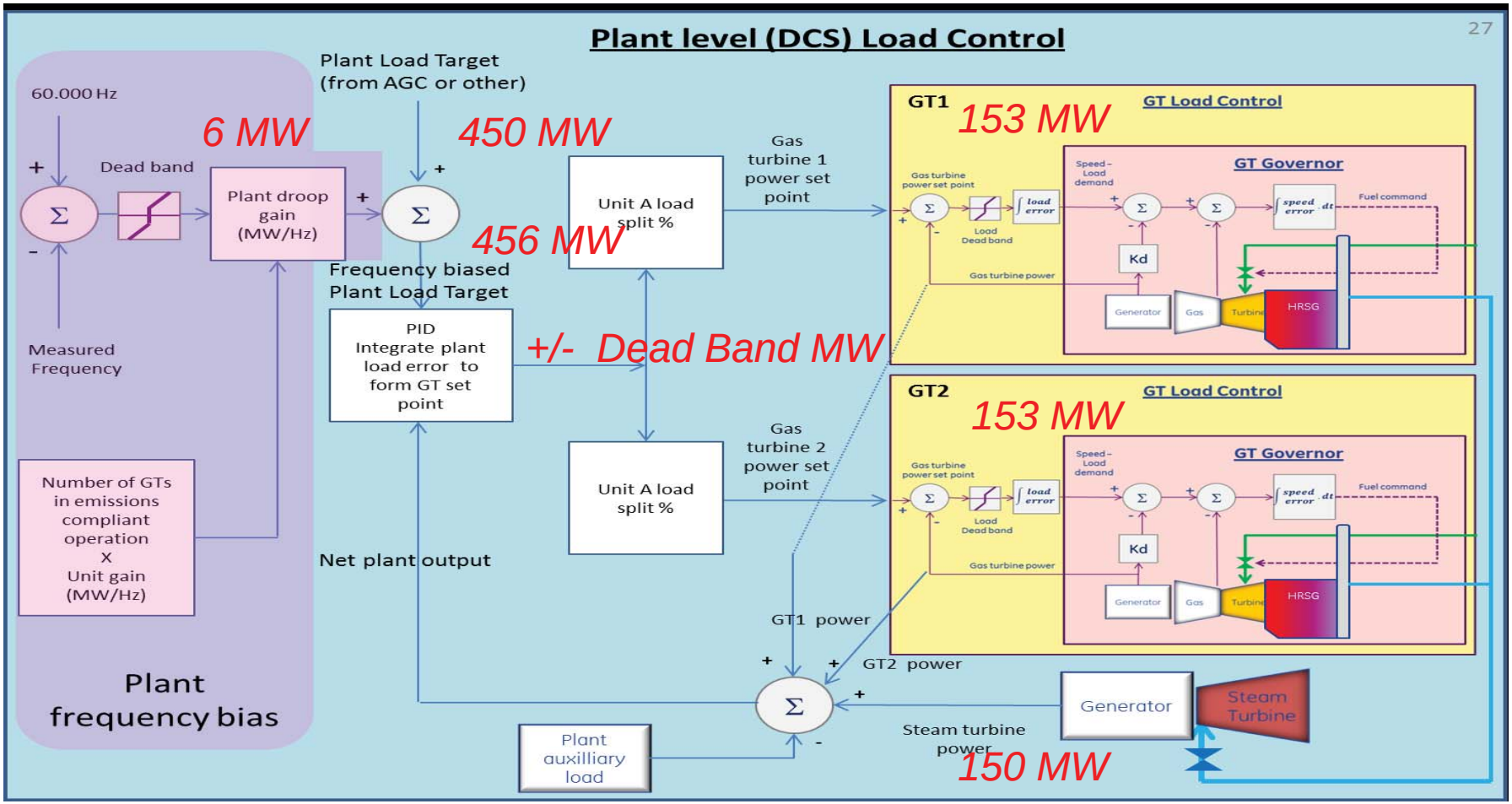
Frequency 59.940 Hz



Graphic from GE info bulletin PSIB20150212

Example

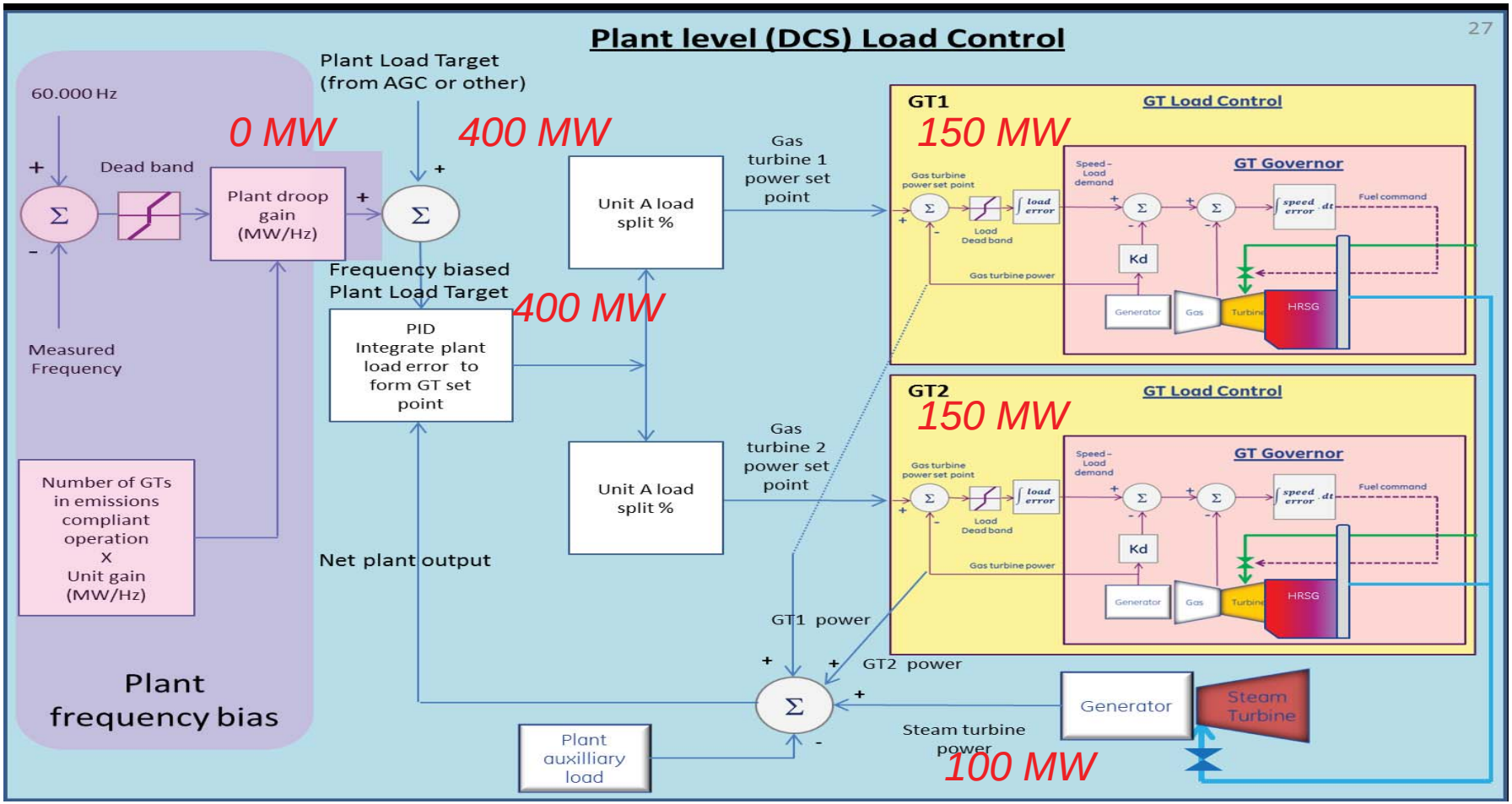
Frequency 59.940 Hz



Graphic from GE info bulletin PSIB20150212

Example

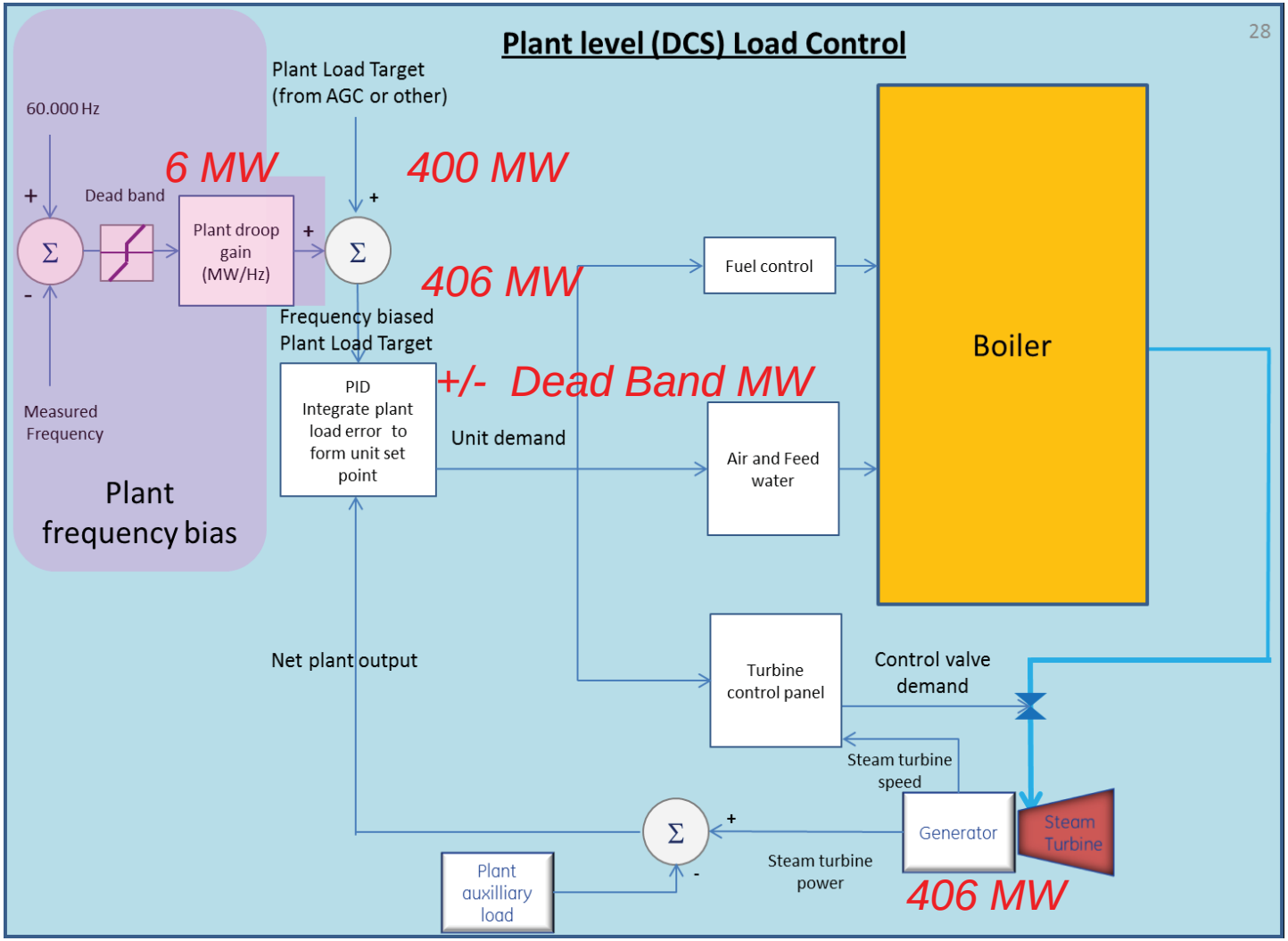
Frequency 60.000 Hz



Graphic from GE info bulletin PSIB20150212

Conventional Steam Plant

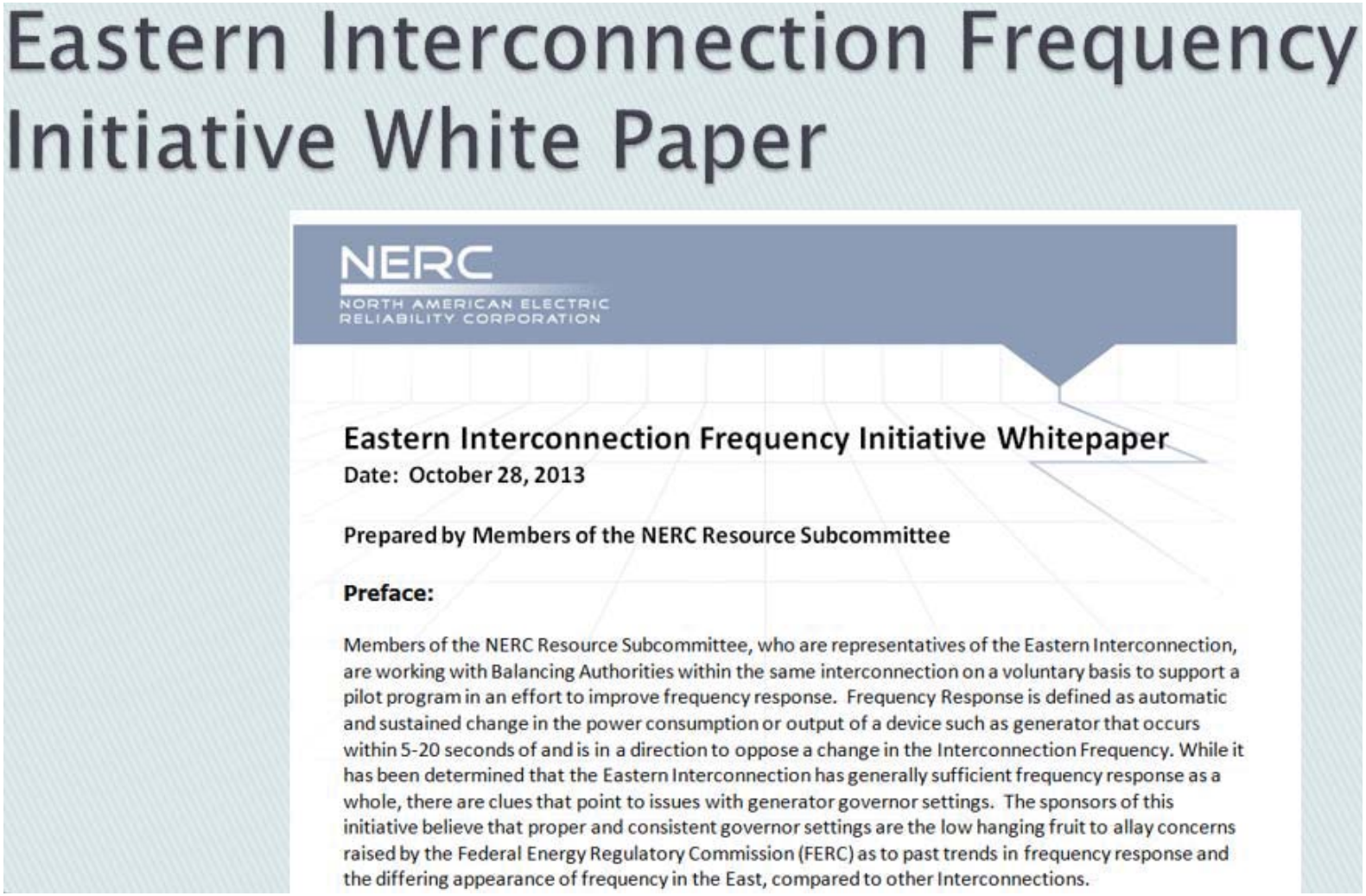
Frequency 59.940 Hz



Graphic from GE info bulletin PSIB20150212

Voluntary Initiative

Eastern Interconnection Frequency Initiative White Paper



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Eastern Interconnection Frequency Initiative Whitepaper

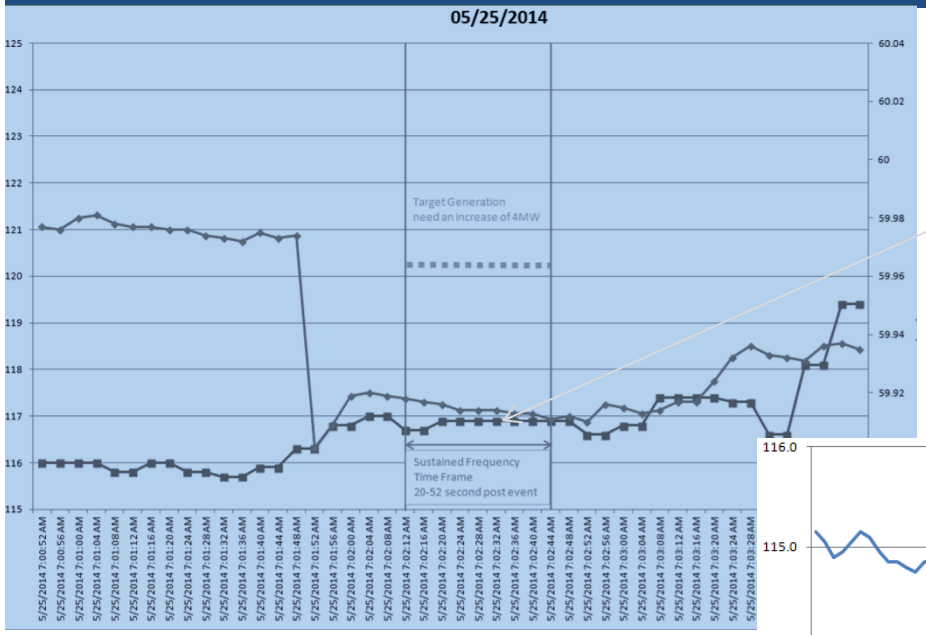
Date: October 28, 2013

Prepared by Members of the NERC Resource Subcommittee

Preface:

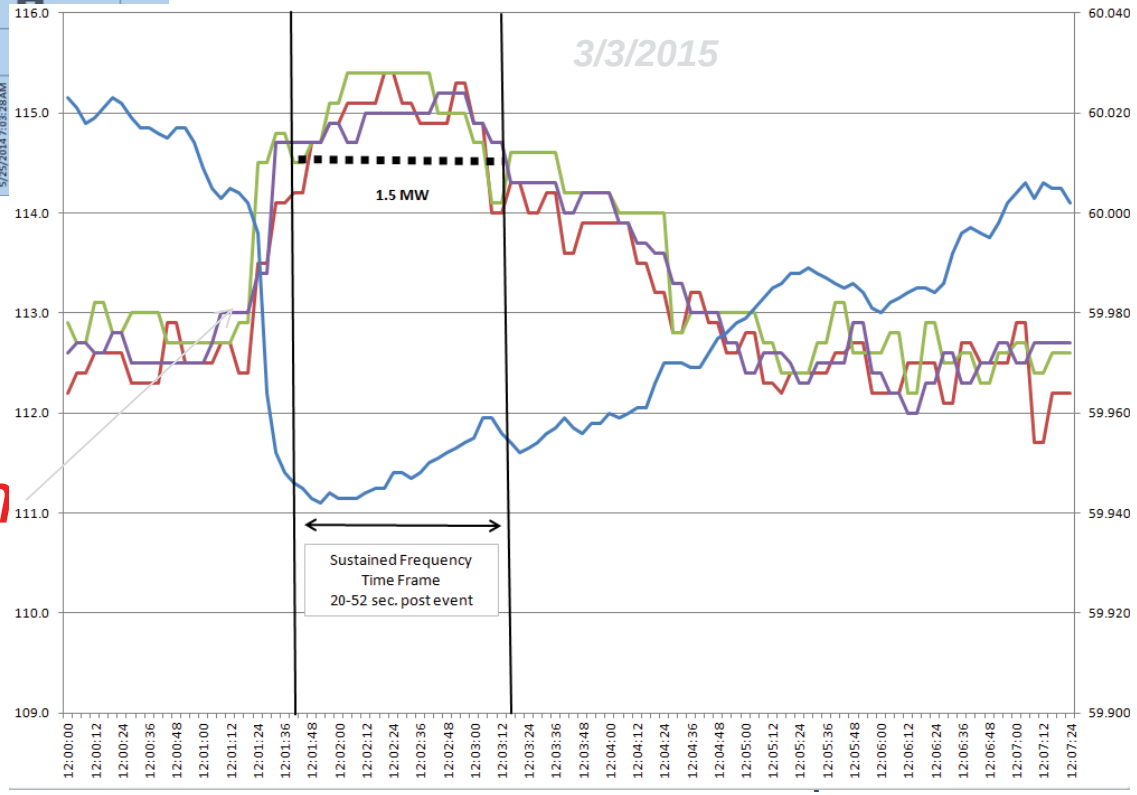
Members of the NERC Resource Subcommittee, who are representatives of the Eastern Interconnection, are working with Balancing Authorities within the same interconnection on a voluntary basis to support a pilot program in an effort to improve frequency response. Frequency Response is defined as automatic and sustained change in the power consumption or output of a device such as generator that occurs within 5-20 seconds of and is in a direction to oppose a change in the Interconnection Frequency. While it has been determined that the Eastern Interconnection has generally sufficient frequency response as a whole, there are clues that point to issues with generator governor settings. The sponsors of this initiative believe that proper and consistent governor settings are the low hanging fruit to allay concerns raised by the Federal Energy Regulatory Commission (FERC) as to past trends in frequency response and the differing appearance of frequency in the East, compared to other Interconnections.

Improvements



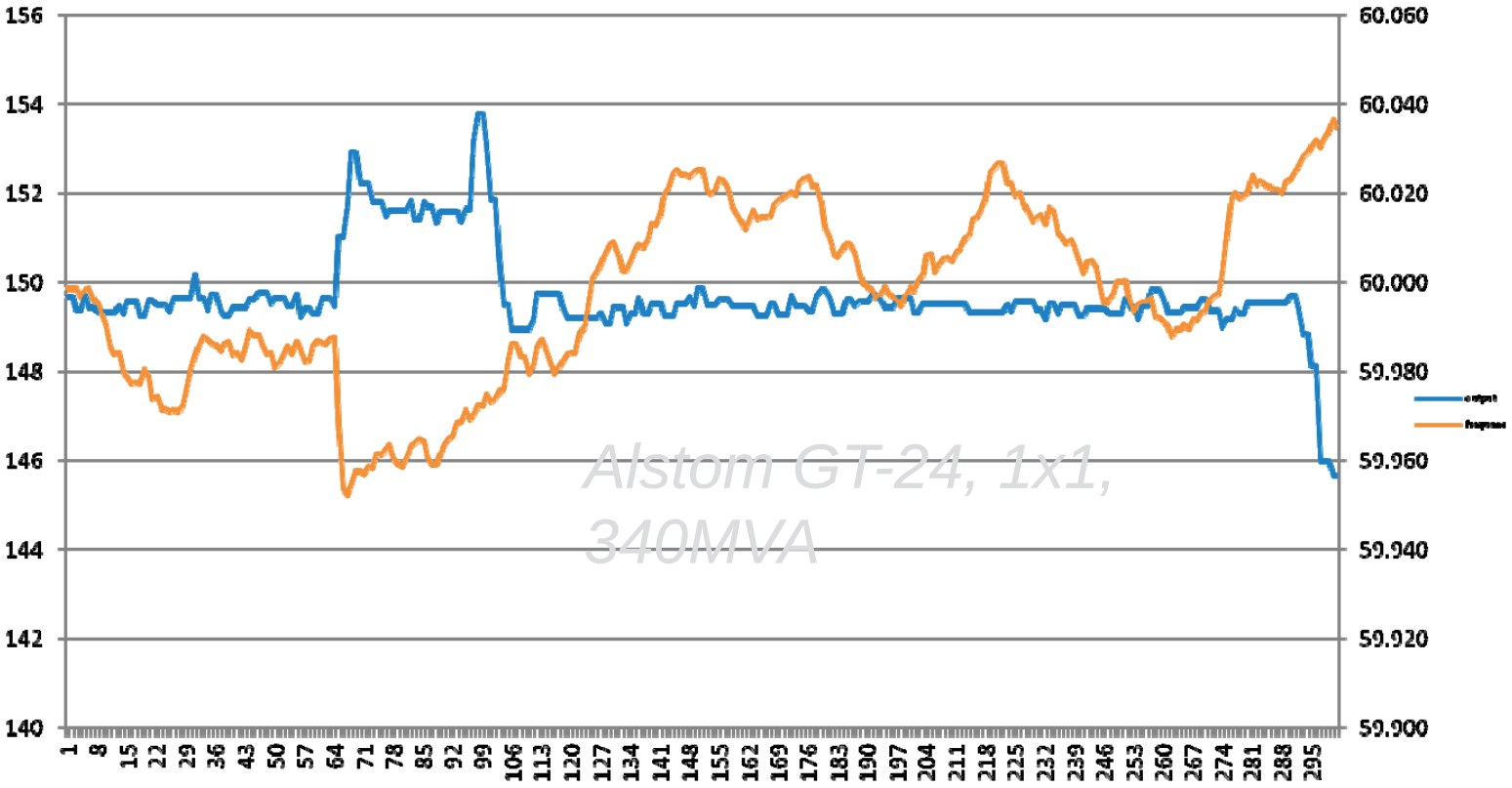
No Frequency Algorithm in DCS

3 -175 MW GE7FA Gas Mark VIe Turbine



Frequency Algorithm in Plant DCS

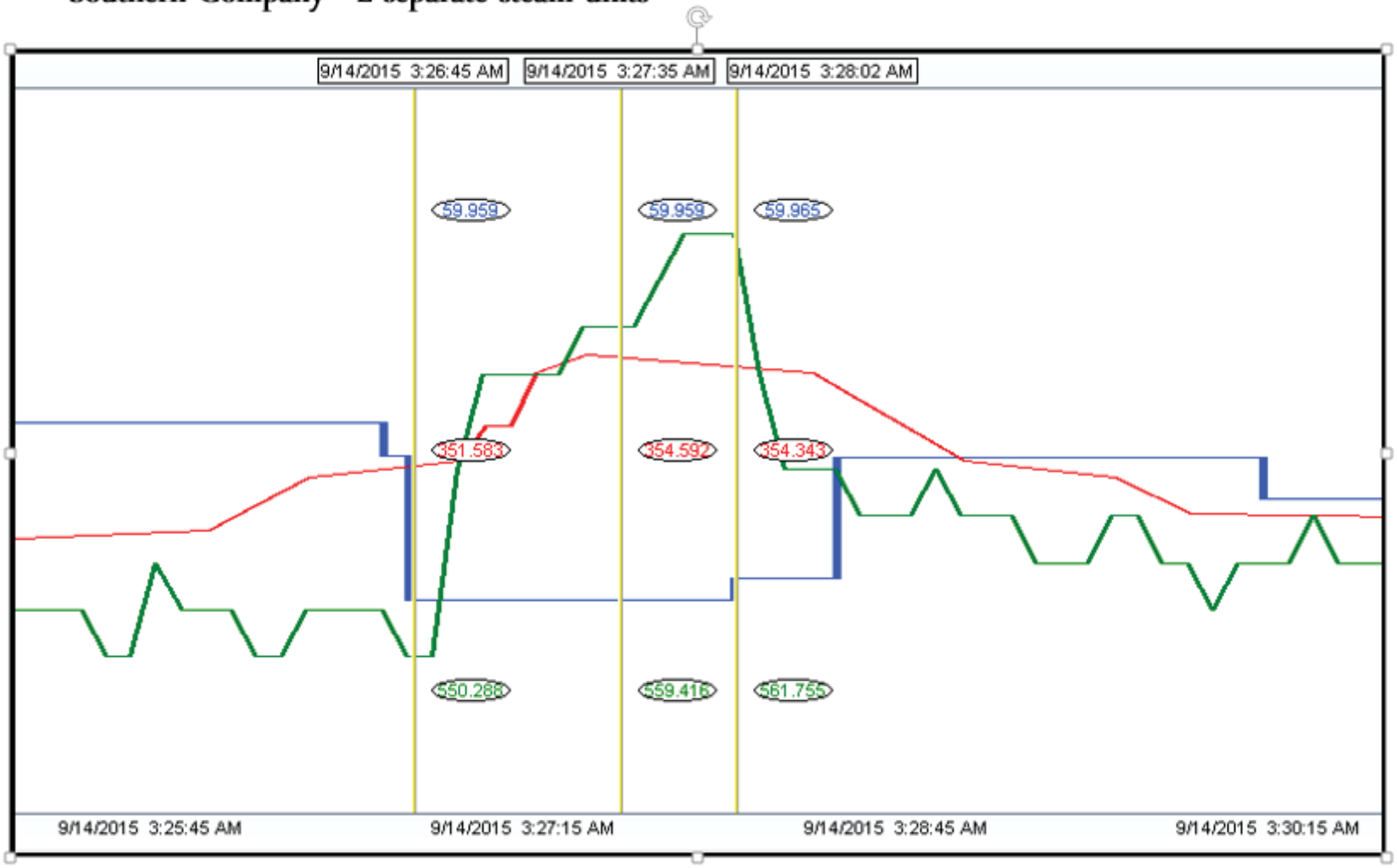
ISONE Generator Frequency Response after remediation (Sustained)



Provided by ISO-NE

Improvements

Southern Company – 2 separate steam units



Provided by Southern Company

Reliability Guideline: Primary Frequency Control

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Reliability Guideline
Primary Frequency Control

Preamble

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

Frequency Control

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

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

Definitions Used

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

RELIABILITY | ACCOUNTABILITY

Posted 12/15/2015

ERCOT Interconnection

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

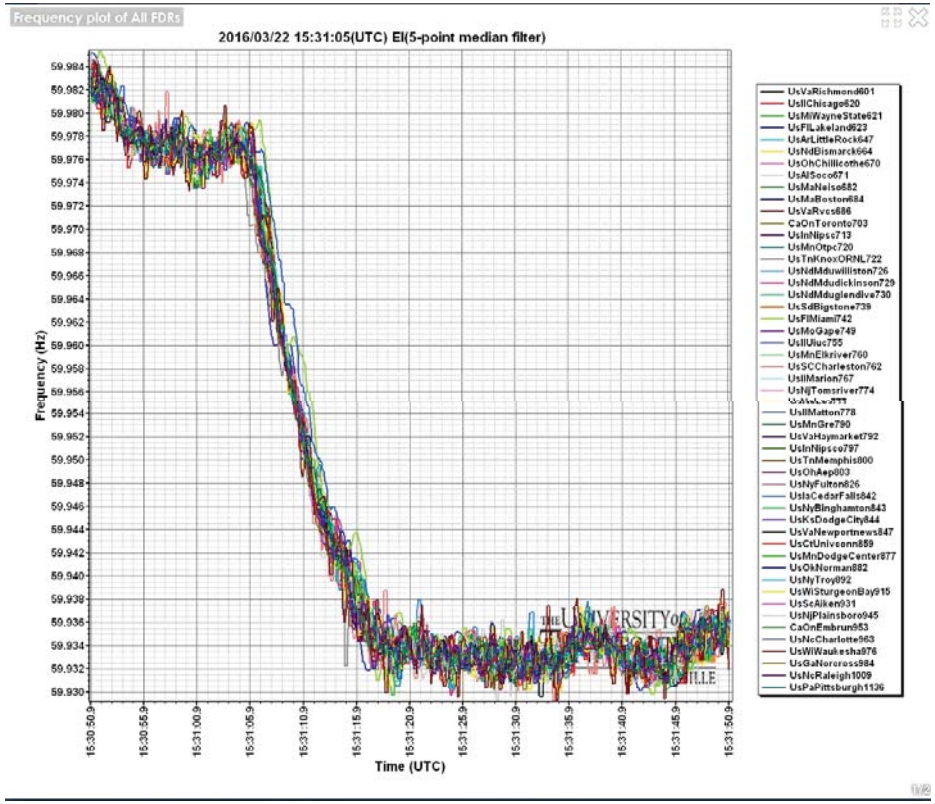
1. **Deadband** –The deadband setting should not exceed the following :

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

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

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

Eastern Profile Changing ? New Trend



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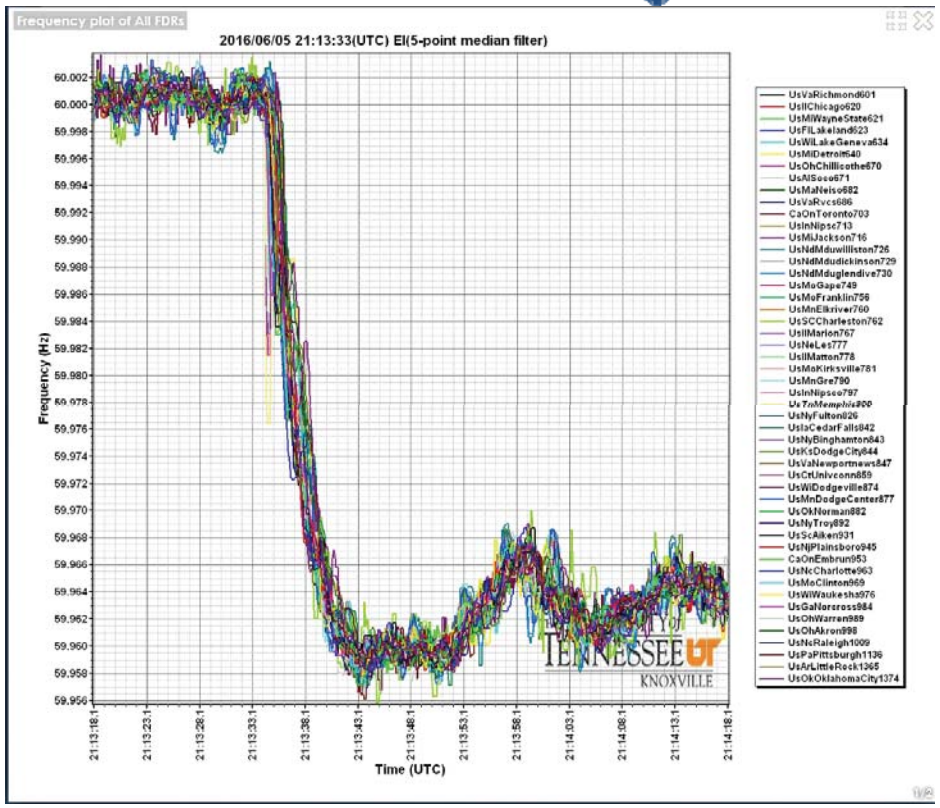
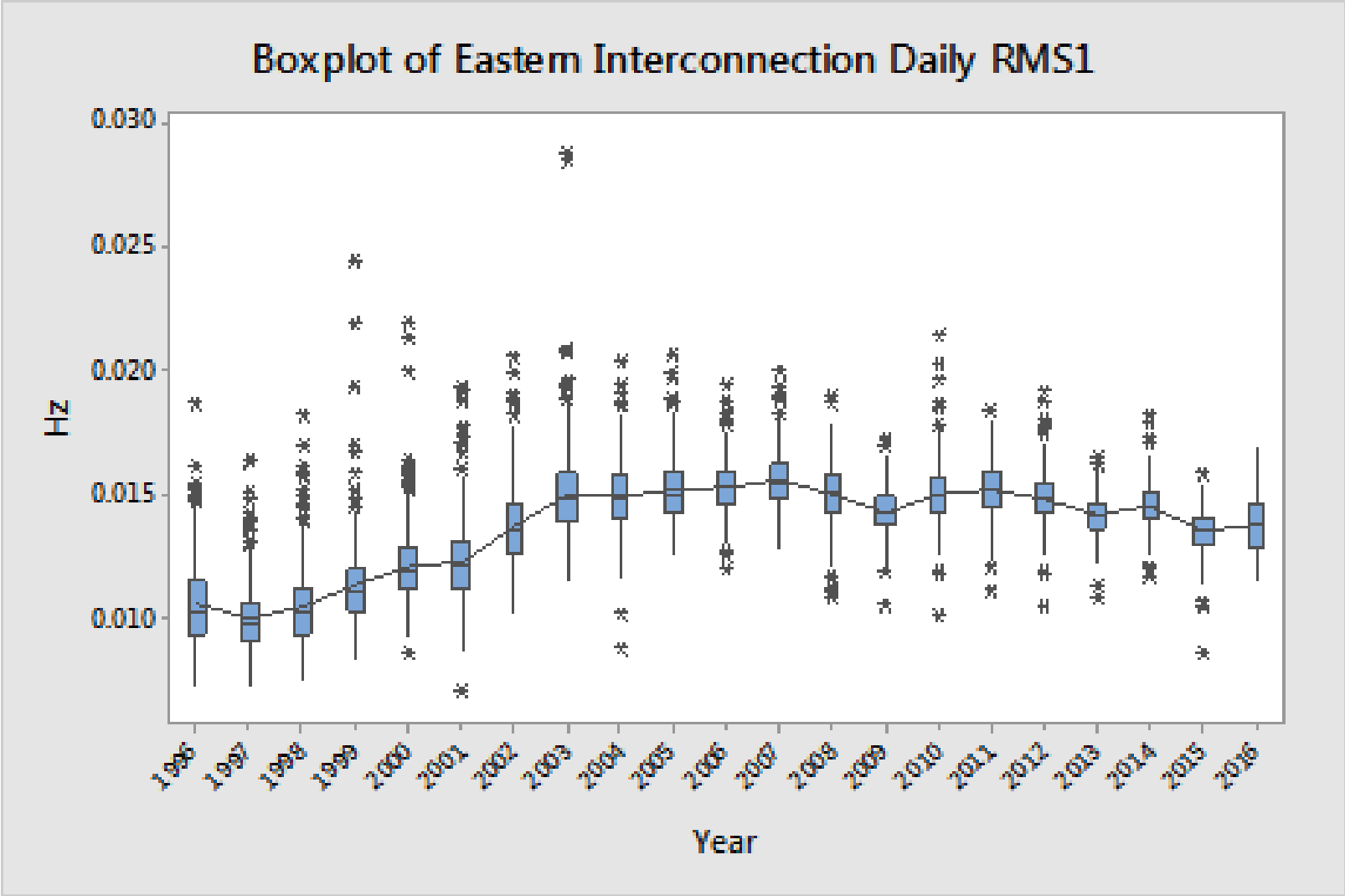
1111 MW Trip



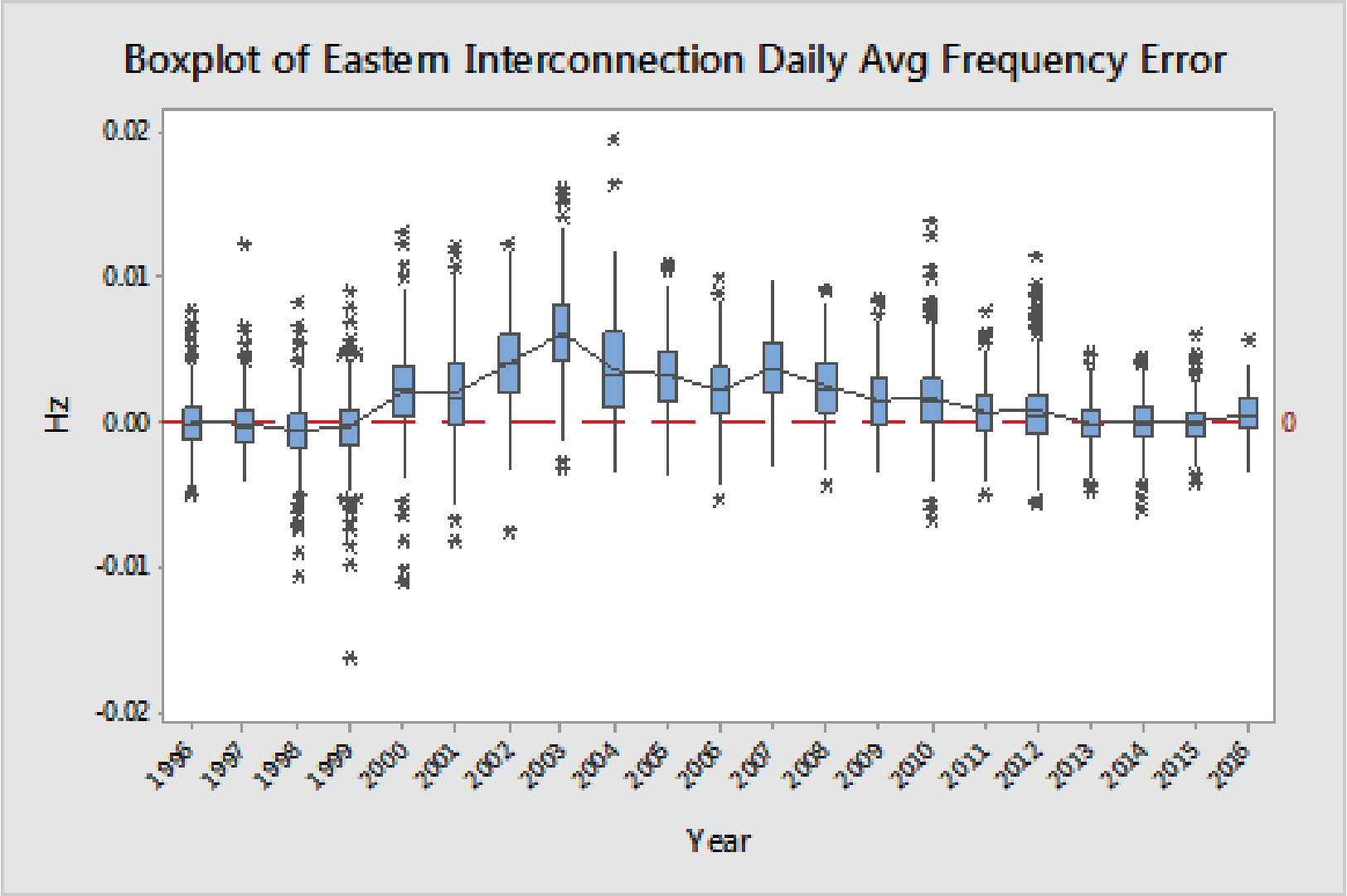
06/05/16 17:15 EST

918 MW Trip

Eastern Interconnection



Eastern Interconnection



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2015 Interconnection Frequency Response Performance

2015 BAL-003-1 Performance

		Balancing Authority	MyBA		NERC FRS FORM 1 20 to 52 second Value B										Enter Addition Data in column W ==>	
Date/Time (t-0)	Time	Date/Time (t-0)	BA Time		BA	BA Bias	Relay Lmt R1	Value "A" Information		Value "B" Information		SEFRD (FRM) for Bias	SEFRD (FRM) for R1	Exclude for	Enter Data in Green Highlighted Cells	
(Central Prevailing)	Zone	BA Time	Zone	DelFreq	Time	DelFreq	DelFreq	NAI	Adjustment	NAI	Adjustment	(MW/0.1Hz)	(MW/0.1Hz)	data error *	Upload Form 1 and all Form 2s to the NERC ftp site:	
12/01/2013 5:13:22	CST	12/1/2013 6:13:22	EST	-0.049	6:13:24	-0.049	-0.049	324.3	0.0	337.7	0.0	-27.4	-27.4	N		
12/9/2013 7:46:58	CST	12/9/2013 8:46:58	EST	-0.048	8:47:00	-0.047	-0.047	335.0	0.0	307.3	0.0	59.0	59.0	N		
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2/15/2014 21:54:14	CST	2/15/2014 22:54:14	EST	-0.049	22:54:16	-0.047	-0.047	318.3	0.0	362.8	0.0	-93.9	-93.9	N	MyBA	Balancing Authority
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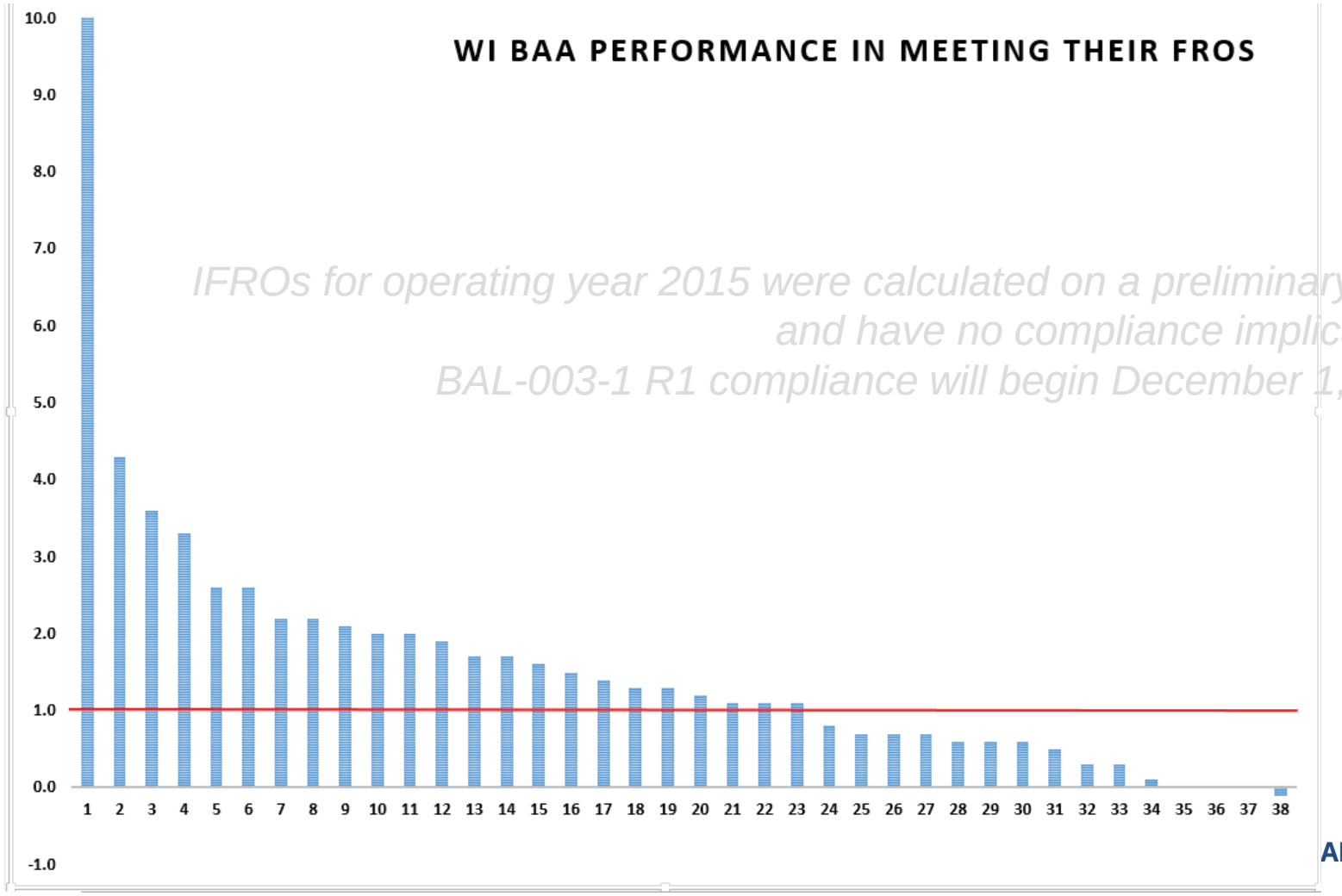
For Operating Year 2015:

- **7 of 35 Eastern Interconnection BAs had preliminary results not yet consistent with their Frequency Response Obligations (FROs)****
  - **Most were small – 5 of the 7 BAs had FROs smaller than -1 MW/.1Hz**
- **15 of 38 Western Interconnection BAs had preliminary results not yet consistent with their FROs**
  - **5 of the 15 had FROs smaller than -1 MW/.1Hz)**

* FROs for operating year 2015 were calculated on a preliminary basis and have no compliance implications. BAL-003-1 R1 compliance will begin December 1, 2016.

2015 Western Interconnection Performance

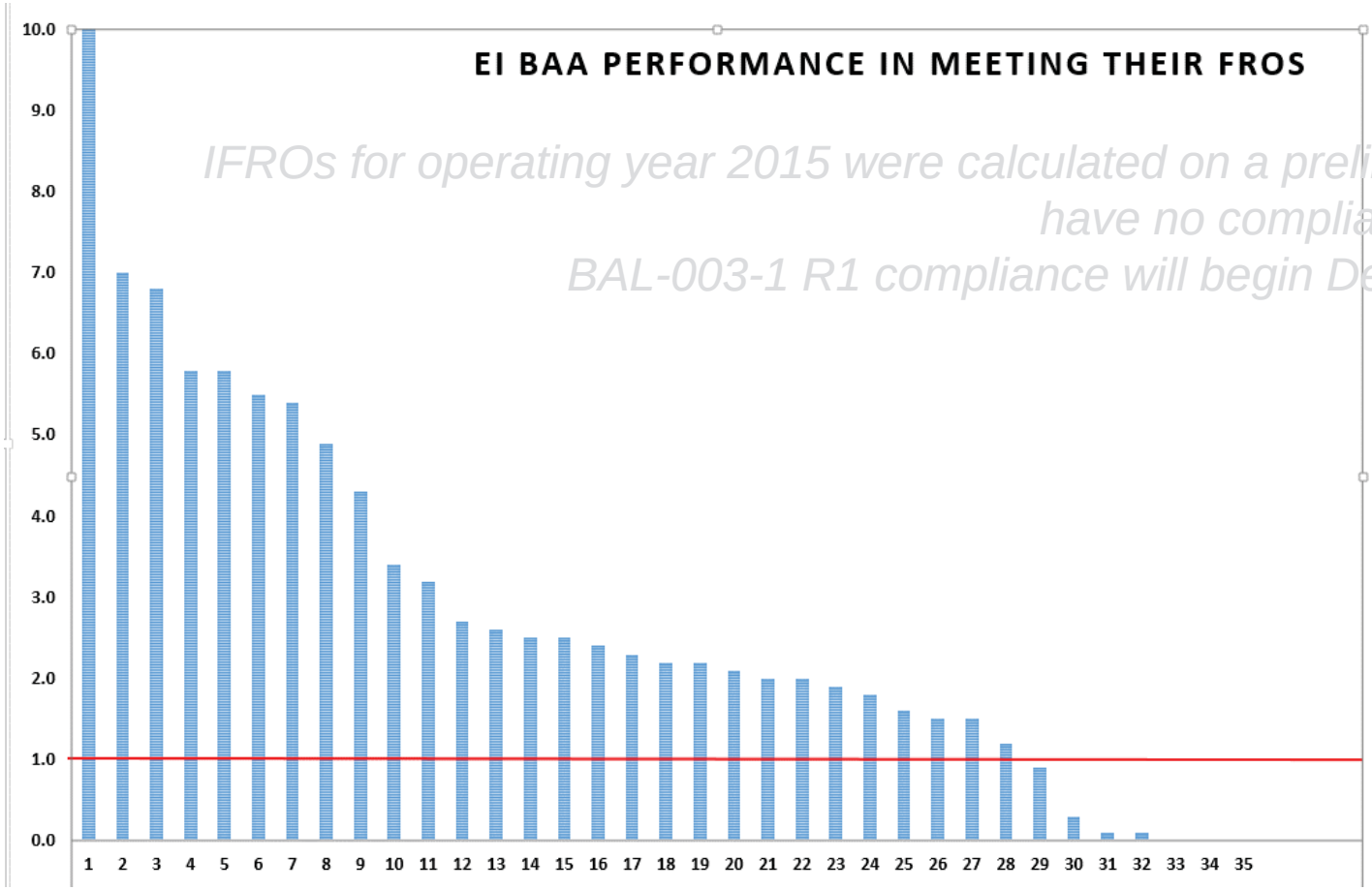
- *Aggregate BA performance 1.3 times greater than 858 IFRO*
- *The WI Met its IFRO 23 of 25 events*



IFROs for operating year 2015 were calculated on a preliminary basis and have no compliance implications.
BAL-003-1 R1 compliance will begin December 1, 2016.

2015 Eastern Interconnection Performance

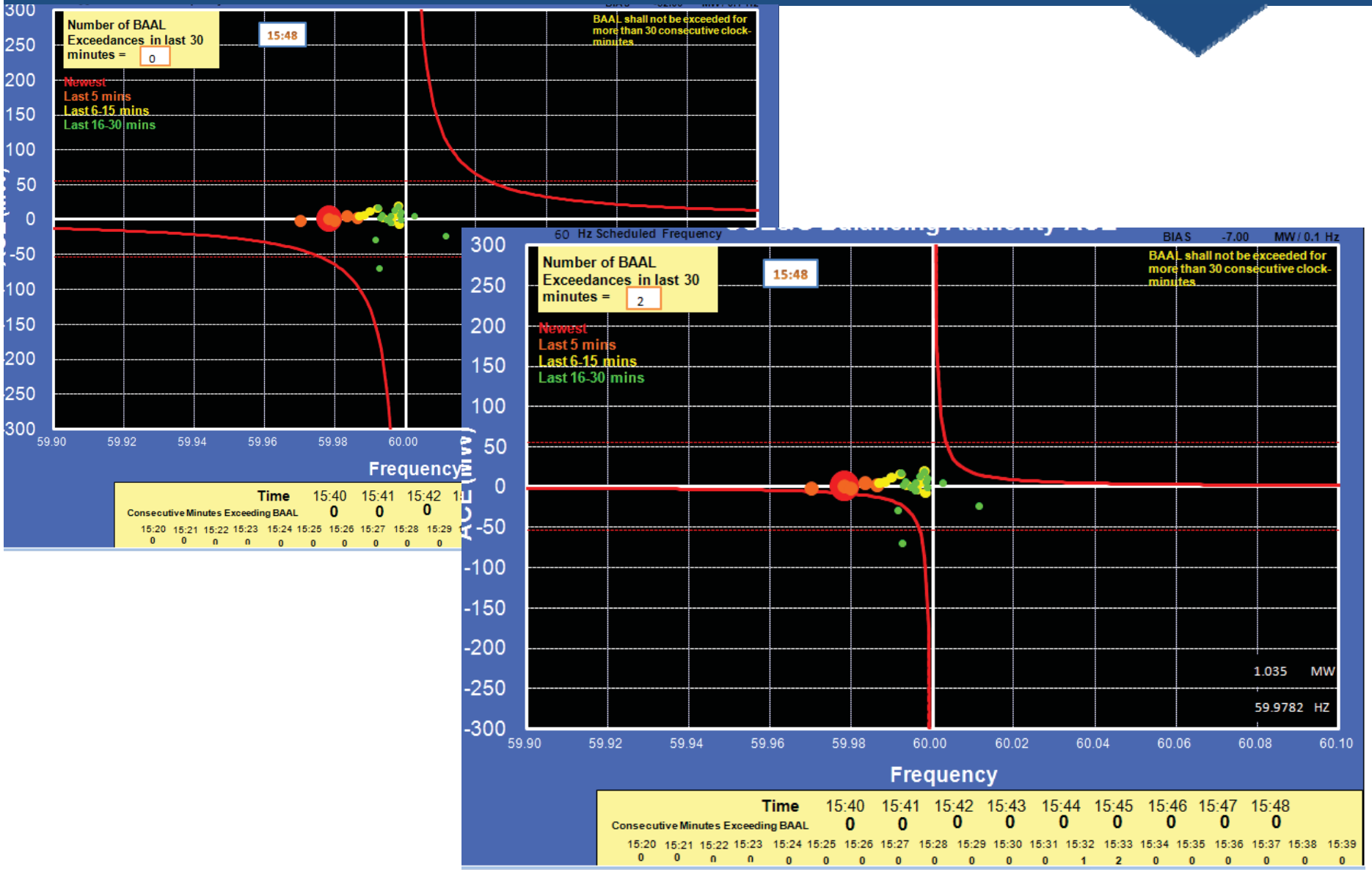
- *Aggregate BA performance 2.3 times greater than 1,015 IFRO*
- *The EI Met its IFRO 30 of 30 events with room to spare*



IFROs for operating year 2015 were calculated on a preliminary basis and have no compliance implications.

BAL-003-1 R1 compliance will begin December 1, 2016.

BAL-001-2 Impact on Reduction of BIAS to FRM



MOD-027-1

Standard MOD-027-1 — Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

A. Introduction

1. **Title:** Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

2. **Number:** MOD-027-1

3. **Purpose:** To verify that the turbine/governor and load control or active power/frequency control[1] model and the model parameters, used in dynamic simulations that assess Bulk Electric System (BES) reliability, accurately represent generator unit real power response to system frequency variations.

Recommendation

Every BES Generator should have a working governor and be set in accordance with Frequency Response Guideline for system reliability and system restoration and provide primary frequency response between Pmin and Pmax.

- Exemptions Nuclear, existing wind and solar, or possibly some others (environmental, etc.)

2012 Generator response analysis study showed:

- Only 30% of the units on-line provide primary frequency response.
- Two-thirds of the units that did respond exhibit withdrawal of primary frequency response
- Only 10% of units on-line sustain primary frequency response

LGIA and SGIA should be modified to require the same for all future generation.

Probable Next Steps

Generator Survey over the next several years.

- If online, Generators will be asked to evaluate their individual performance based on Interconnection events.
- Minimum data request: MW and RPM or Frequency Values at scan-rate (SCADA)
- Most likely two to three events a year

Goal is to continue to bring awareness to the issues identified to the Generator Operators and assist them in correcting issues provide primary frequency response.

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Questions

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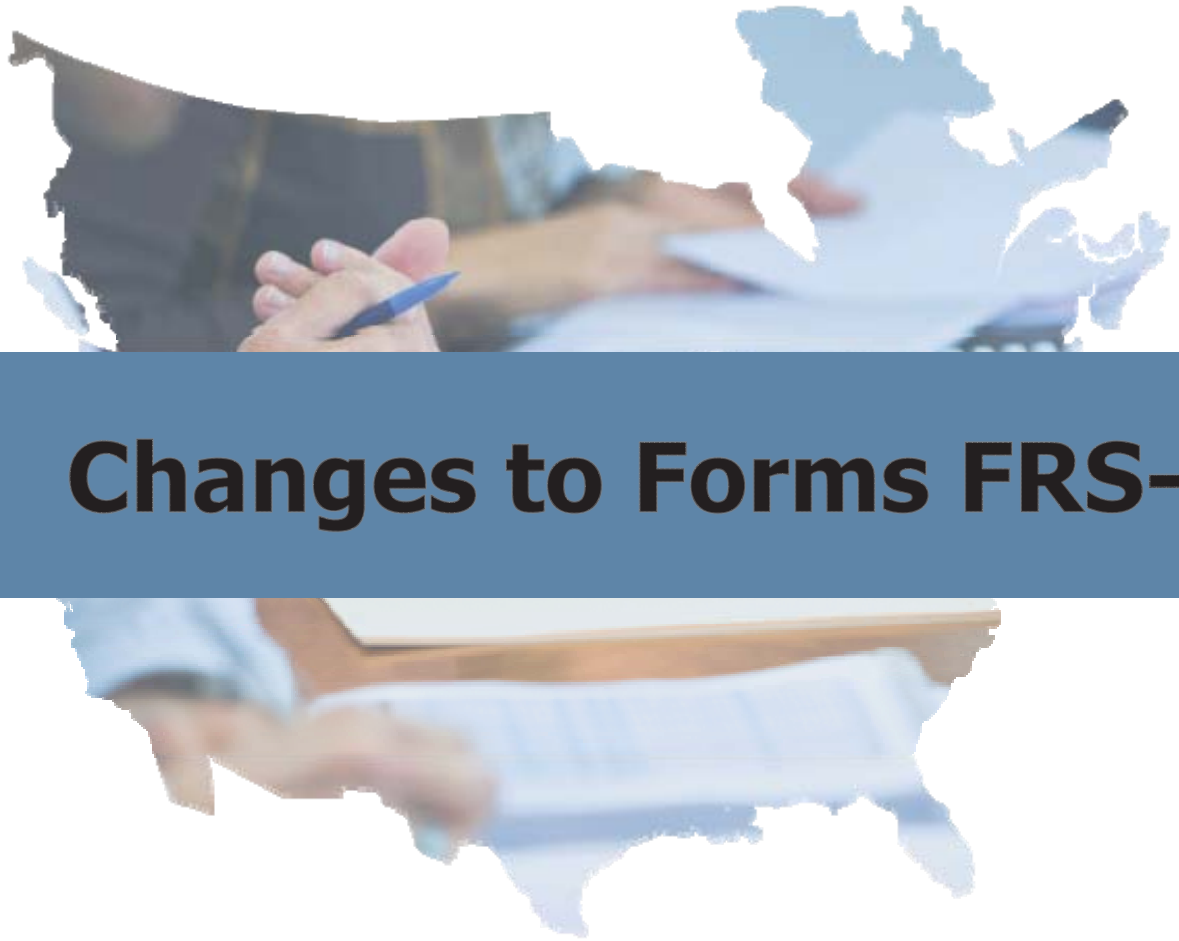

Changes to Forms FRS-1 and FRS-2

Old Form FRS-1

FRS FORM 1 20 to 52 second Value B

Enter Addition Data in column W ==>

ue "A" Information		Value "B" Information		SEFRD (FRM)		Exclude for
l	Adjustment	NAI	Adjustment	for Bias (MW/0.1Hz)	for R1 (MW/0.1Hz)	data error *
)	0.0	0.0	0.0	#DIV/0!	0.0	N
)	0.0	0.0	0.0	#DIV/0!	0.0	N
)	0.0	0.0	0.0	#DIV/0!	0.0	N
)	0.0	0.0	0.0	#DIV/0!	0.0	N
)	0.0	0.0	0.0	#DIV/0!	0.0	N
)	0.0	0.0	0.0	#DIV/0!	0.0	N
)	0.0	0.0	0.0	#DIV/0!	0.0	N
)	0.0	0.0	0.0	#DIV/0!	0.0	N
)	0.0	0.0	0.0	#DIV/0!	0.0	N
)	0.0	0.0	0.0	#DIV/0!	0.0	N
)	0.0	0.0	0.0	#DIV/0!	0.0	N
)	0.0	0.0	0.0	#DIV/0!	0.0	N
)	0.0	0.0	0.0	#DIV/0!	0.0	N
)	0.0	0.0	0.0	#DIV/0!	0.0	N
)	0.0	0.0	0.0	#DIV/0!	0.0	N
)	0.0	0.0	0.0	#DIV/0!	0.0	N
)	0.0	0.0	0.0	#DIV/0!	0.0	N
)	0.0	0.0	0.0	#DIV/0!	0.0	N
)	0.0	0.0	0.0	#DIV/0!	0.0	N
)	0.0	0.0	0.0	#DIV/0!	0.0	N
)	0.0	0.0	0.0	#DIV/0!	0.0	N
)	0.0	0.0	0.0	#DIV/0!	0.0	N
)	0.0	0.0	0.0	#DIV/0!	0.0	N
)	0.0	0.0	0.0	#DIV/0!	0.0	N
)	0.0	0.0	0.0	#DIV/0!	0.0	N
)	0.0	0.0	0.0	#DIV/0!	0.0	N
)	0.0	0.0	0.0	#DIV/0!	0.0	N
)	0.0	0.0	0.0	#DIV/0!	0.0	N
)	0.0	0.0	0.0	#DIV/0!	0.0	N
)	0.0	0.0	0.0	#DIV/0!	0.0	N
)	0.0	0.0	0.0			Y
)	0.0	0.0	0.0			Y
)	0.0	0.0	0.0			Y
)	0.0	0.0	0.0			Y
)	0.0	0.0	0.0			Y
)	0.0	0.0	0.0			Y

Enter Data in Green Highlighted Cells

Upload Form 1 and all Form 2s to the NERC BASS:

2016	Bias Calculation Form 1 for Year
Eastern	Interconnection
FPC	Balancing Authority
	Contact Name
	Contact Phone #
	Contact e-mail
38,633,990	MWh Annual Gen_{BA} is the annual "Net Generation (MWh)", FERC Form 714, line 13, column c of Part II - Schedule 3.
51,185,656	MWh Annual $Load_{BA}$ is the annual "Net Energy for Load (MWh)", FERC Form 714, line 13, column e of Part II - Schedule
3,106,225,398	MWh Annual Gen_{INT} is the Sum of all Annual Gen_{BA} values in this interconnection
3,142,667,030	MWh Annual $Load_{INT}$ is the Sum of all Annual $Load_{BA}$ values in this interconnection
-1015	Interconnection Frequency Response Obligation (FRO) MW/0.1 Hz. Determined by ERO.
2015	Current Operating Year (December thru November)
-14.59	**2016 BA Frequency Response Obligation (FRO) for next year's FRM**
	2015 BA Frequency Response Obligation (FRO) for this year's FRM from your last year's Form 1.
Calculate Regression	**BA Bias Type and Bias Setting**
Fixed	Bias Type utilized.
0.9%	Interconnection Minimum Fixed Frequency Bias Setting % of Peak Demand or Peak Generation (Set by ERO)
581790	The Sum of the Non-Coincident peak demands for all Bas on the interconnection from FERC Form No. 714, provided b
-75.26	Your BA's lowest absolute Fixed Frequency Bias Setting based on interconnection non-coincident peak demand.
	Your BA's lowest absolute Fixed Frequency Bias Setting based on 100% of FRM.
	Your BA's highest absolute Fixed Bias Setting: 125% of FRM.
n/a	Balancing Authority lowest absolute Variable Bias Setting (least negative one minute average Bias while frequency is l
	Balancing Authority desired Bias Setting: May be set to a value between 100% to 125% of its FRM if this value is more r based on Peak Demand. If not more negative, then the Bias must be the minimum Bias based on Peak Demand. If va
-75.26	**2016 Frequency Bias Setting - (minimum of 100% to 125% of FRM, or 0.9% of Historical Peak Demand if not Variable**
#DIV/0!	2015 FRM - Average Estimated Frequency Response MW/0.1 Hz using SEFRD for Bias
0.00	2015 FRM - Regression Estimated Frequency Response MW/0.1Hz using SEFRD for Bias
#DIV/0!	2015 FRM - Median Estimated Frequency Response MW/0.1Hz using SEFRD for Bias
0.00	2015 FRM - Average Estimated Frequency Response MW/0.1 Hz using SEFRD for R1
0.00	2015 FRM - Regression Estimated Frequency Response MW/0.1Hz using SEFRD for R1
0.00	**2015 FRM - Median Estimated Frequency Response MW/0.1Hz for BA Compliance to R1, minimum Frequency Respo**

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Revised Form FRS-1

52 second Value B

Information seconds Adjustment	SEFRD (FRM) for Bias (MW/0.1Hz)	SEFRD (FRM) for R1 (MW/0.1Hz)	Exclude for data error *
0.0	#DIV/0!	0.0	N
0.0	#DIV/0!	0.0	N
0.0	#DIV/0!	0.0	N
0.0	#DIV/0!	0.0	N
0.0	#DIV/0!	0.0	N
0.0	#DIV/0!	0.0	N
0.0	#DIV/0!	0.0	N
0.0	#DIV/0!	0.0	N
0.0	#DIV/0!	0.0	N
0.0	#DIV/0!	0.0	N
0.0	#DIV/0!	0.0	N
0.0	#DIV/0!	0.0	N
0.0	#DIV/0!	0.0	N
0.0	#DIV/0!	0.0	N
0.0	#DIV/0!	0.0	N
0.0	#DIV/0!	0.0	N
0.0	#DIV/0!	0.0	N
0.0	#DIV/0!	0.0	N
0.0	#DIV/0!	0.0	N
0.0	#DIV/0!	0.0	N
0.0	#DIV/0!	0.0	N
0.0	#DIV/0!	0.0	N
0.0	#DIV/0!	0.0	N
0.0	#DIV/0!	0.0	N
0.0	#DIV/0!	0.0	N
0.0			Y
0.0			Y
0.0			Y
0.0			Y
0.0			Y
0.0			Y
0.0			Y
0.0			Y
0.0			Y
0.0			Y
0.0			Y
0.0			Y
0.0			Y

Enter Addition Data in columns V through X ==>

Enter Data in Green Highlighted Cells
Upload Form 1 and all Form 2s to the NERC BASS:
Grey and light blue cells are calculated or set by the ERO.

FRM Performance Results for 2016

0.00	**2016 FRM - Median Estimated Frequency Response MW/0.1Hz for BA Compliance to R1, minimum Frequency Response**
-25.49	**2016 BA Frequency Response Obligation (FRO)**
0.00	2016 FRM - Average Estimated Frequency Response MW/0.1 Hz using SEFRD for R1
0.00	2016 FRM - Regression Estimated Frequency Response MW/0.1Hz using SEFRD for R1

Bias Calculation Worksheet for 2017

Western	Interconnection
LDWP	Balancing Authority
	Contact Name
	Contact Phone #
	Contact e-mail
21,796,949	MWh Annual Gen$_{BA}$ is the annual "Net Generation (MWh)", FERC Form 714, line 13, column c of Part II - Schedule 3.
29,696,030	MWh Annual Load$_{BA}$ is the annual "Net Energy for Load (MWh)", FERC Form 714, line 13, column e of Part II - Schedule 3.
859,774,646	MWh Annual Gen$_{INT}$ is the Sum of all Annual Gen$_{BA}$ values in this interconnection
873,709,347	MWh Annual Load$_{INT}$ is the Sum of all Annual Load$_{BA}$ values in this interconnection
-858	Interconnection Frequency Response Obligation (FRO) MW/0.1 Hz. Determined by ERO.
2016	Current Operating Year (December thru November)
TBD	**Operating Year 2017 BA Frequency Response Obligation (FRO) for next year's FRM**
-25.49	**Operating Year 2016 BA Frequency Response Obligation (FRO).**

BA Bias Type and Bias Setting

Calculate Regression	
Fixed	Select Bias Type utilized.
0.9%	Interconnection Minimum Fixed Frequency Bias Setting % of Peak Demand or Peak Generation (Set by ERO)
166,257	The Sum of the Non-Coincident peak demands for all Bas on the interconnection from FERC Form No. 714, provided by ERO.
-44.45	Your BA's lowest absolute Fixed Frequency Bias Setting based on interconnection non-coincident peak demand.
	Your BA's lowest absolute Fixed Frequency Bias Setting based on 100% of FRM.
	Your BA's highest absolute Fixed Bias Setting: 125% of FRM.
n/a	Balancing Authority lowest absolute Variable Bias Setting (least negative one minute average Bias while frequency is less than 59.964 or greater than 60.0
	Enter Balancing Authority desired Bias Setting: May be set to a value between 100% to 125% of its FRM if this value is more negative than the minimum Bia based on Peak Demand. If not more negative, then the Bias must be the minimum Bias based on Peak Demand. If variable Bias is used, enter "Variable".
-44.45	**2016 Frequency Bias Setting - (minimum of 100% to 125% of FRM, or 0.9% of Historical Peak Demand if not Variable)**
#DIV/0!	2016 FRM - Average Estimated Frequency Response MW/0.1 Hz using SEFRD for Bias

2014 Form 714 Data | Adjustments | Variable Bias Supplemental Info | BA Form 2 Event Data | TimeZone Ref | Frequency Response Initiative | Change Hist ...

Changes made to FRS Forms 1 & 2

FRS Form-1

- Reorganized to separate calculation of FRM from Bias
- Locked calculated cells and data source pages (e.g., Forms 714 Data)
- All required data entry instructions color-coded in amber
- All data input sells are color-coded in light green
- All calculated values color-coded in light blue
- Will be adding 2015 FERC Form 714 data in December 2016 for use in calculating Frequency Bias Settings and L_{10} for 2017 Bias year (April 2017 through March 2018)

FRS Form-2.2

- Added JOU & FR Transfer Sheet
- Modified Data Sheet to incorporate Aggregate JOU & FR Transfers

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Revised Form FRS-2.2 – Data Sheet

A	B	C	D	E	F	G	H	I	J	K	L	M	N
			Aggregate JOU	Non-			Aggregate Transferred	Contingent				Event Detection	Recovery Target Freq:
		Net	Dynamic	Conforming	Pumped	Not	Frequency	BA	BA	BA		Row	60.000
		Actual	Schedules	Load	Hydro	Used	Response	Lost Generation	Bias	Load		306	2:27:26
		Interchang	Imp(-) Exp (+)	Load (-)	Load (-) Gen (+)		Rec (-) Del (+)	Load (-) Gen (+)	Setting			473	2:33:00
Date/Time (T)	Hz	MW	MW	MW	MW		MW/0.1 Hz	MW	MW/0.1 Hz	MW		307	05:34
10/12/09 02:19:38	59.987	3670.476	0	-260.36441	0		0	15	-103	7575.57		0	0
10/12/09 02:19:40	59.987	3670.129	0	-352.644379	0		0	15	-103	7575.9		0	0
10/12/09 02:19:42	59.985	3671.542	0	-352.644379	0		0	15	-103	7576.23		0	0
10/12/09 02:19:44	59.984	3672.048	0	-352.644379	0		0	15	-103	7576.56		0	0
10/12/09 02:19:46	59.982	3671.576	0	-352.644379	0		0	15	-103	7576.89		0	0
10/12/09 02:19:48	59.983	3672.104	0	-352.644379	0		0	15	-103	7577.22		0	0
10/12/09 02:19:50	59.989	3672.414	0	-354.89566	0		0	15	-103	7577.55		0	0
10/12/09 02:19:52	59.989	3671.882	0	-354.89566	0		0	15	-103	7577.88		0	0
10/12/09 02:19:54	59.988	3671.837	0	-354.89566	0		0	15	-103	7578.21		0	0
10/12/09 02:19:56	59.984	3671.336	0	-354.89566	0		0	15	-103	7578.54		0	0
10/12/09 02:19:58	59.982	3670.726	0	-354.89566	0		0	15	-103	7578.87		0	0
10/12/09 02:20:00	59.983	3670.372	0	-340.46936	0		0	15	-103	7579.2		0	0
10/12/09 02:20:02	59.981	3671.364	0	-340.46936	0		0	15	-103	7579.53		0	0
10/12/09 02:20:04	59.982	3671.401	0	-340.46936	0		0	15	-103	7579.86		0	0
10/12/09 02:20:06	59.983	3672.156	0	-340.46936	0		0	15	-103	7580.19		0	0
10/12/09 02:20:08	59.986	3672.181	0	-340.46936	0		0	15	-103	7580.52		0	0
10/12/09 02:20:10	59.989	3670.296	0	-337.642914	0		0	15	-103	7580.85		0	0
10/12/09 02:20:12	59.987	3668.071	0	-337.642914	0		0	15	-103	7581.18		0	0
10/12/09 02:20:14	59.985	3668.59	0	-337.642914	0		0	15	-103	7581.51		0	0
10/12/09 02:20:16	59.98	3669.908	0	-337.642914	0		0	15	-103	7581.84		0	0
10/12/09 02:20:18	59.98	3670.399	0	-337.642914	0		0	15	-103	7582.17		0	0
10/12/09 02:20:20	59.983	3670.263	0	-284.36084	0		0	15	-103	7582.5		0	0
10/12/09 02:20:22	59.98	3669.382	0	-284.36084	0		0	15	-103	7582.83		0	0
10/12/09 02:20:24	59.979	3670.102	0	-284.36084	0		0	15	-103	7583.16		0	0
10/12/09 02:20:26	59.979	3670.438	0	-284.36084	0		0	15	-103	7583.49		0	0
10/12/09 02:20:28	59.981	3671.403	0	-284.36084	0		0	15	-103	7583.82		0	0
10/12/09 02:20:30	59.981	3672.442	0	-260.467987	0		0	15	-103	7584.15		0	0
10/12/09 02:20:32	59.98	3672.372	0	-260.467987	0		0	15	-103	7584.48		0	0
10/12/09 02:20:34	59.98	3671.947	0	-260.467987	0		0	15	-103	7584.81		0	0
10/12/09 02:20:36	59.981	3670.938	0	-260.467987	0		0	15	-103	7585.14		0	0

Data | JOU & FR Transfers | Copy Results | Evaluation | Graph 20 to 52s | Sustained Graph | Bias ...

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Revised Form FRS-2.2 – New JOU & FR Transfers Sheet

	A	B	C	D	E	F	G	H	I	J	K	L	M
			Joint-Owned Unit Transfers										
			JOU 1	JOU 2	JOU 3	JOU 4	JOU 5	JOU 6	JOU 7	JOU 8	JOU 9	JOU 10	Aggregate
			Dyn. Sched.	Dyn. Sched.	Dyn. Sched.	Dyn. Sched.	Dyn. Sched.	Dyn. Sched.	Dyn. Sched.	Dyn. Sched.	Dyn. Sched.	Dyn. Sched.	JOU Dyn. Sched.
			Imp(-) Exp (+)	Imp(-) Exp (+)	Imp(-) Exp (+)	Imp(-) Exp (+)	Imp(-) Exp (+)	Imp(-) Exp (+)	Imp(-) Exp (+)	Imp(-) Exp (+)	Imp(-) Exp (+)	Imp(-) Exp (+)	Imp(-) Exp (+)
	Date/Time (T)		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
	10/12/09 02:17:26												0.0
	10/12/09 02:17:28												0.0
	10/12/09 02:17:30			10.0			10.0						20.0
	10/12/09 02:17:32			10.0			20.0						30.0
	10/12/09 02:17:34			10.0			33.0						43.0
	10/12/09 02:17:36			10.0			0.0						10.0
	10/12/09 02:17:38						21.0						21.0
	10/12/09 02:17:40			300.0			55.0						355.0
	10/12/09 02:17:42												0.0
	10/12/09 02:17:44			89.0									89.0
	10/12/09 02:17:46			12.0									12.0
	10/12/09 02:17:48			5.0									5.0
	10/12/09 02:17:50			65.0									65.0
	10/12/09 02:17:52			9.0									9.0
	10/12/09 02:17:54			47.0									47.0
	10/12/09 02:17:56			10.0									10.0
	10/12/09 02:17:58			6.0									6.0
	10/12/09 02:18:00			5.0									5.0
	10/12/09 02:18:02												0.0
	10/12/09 02:18:04												0.0
	10/12/09 02:18:06												0.0
	10/12/09 02:18:08												0.0
	10/12/09 02:18:10												0.0
	10/12/09 02:18:12												0.0
	10/12/09 02:18:14												0.0
	10/12/09 02:18:16												0.0
	10/12/09 02:18:18												0.0
	10/12/09 02:18:20												0.0
	10/12/09 02:18:22												0.0
	10/12/09 02:18:24												0.0
	10/12/09 02:18:26												0.0

Bias Selection Detail

Calculate Regression	BA Bias Type and Bias Setting
Fixed	Select Bias Type utilized.
0.9%	Interconnection Minimum Fixed Frequency Bias Setting % of Peak Demand or Peak Generation (Set by ERO)
166,257	The Sum of the Non-Coincident peak demands for all Bas on the interconnection from FERC Form No. 714, provided by ERO.
-44.45	Your BA's lowest absolute Fixed Frequency Bias Setting based on interconnection non-coincident peak demand.
	Your BA's lowest absolute Fixed Frequency Bias Setting based on 100% of FRM.
	Your BA's highest absolute Fixed Bias Setting: 125% of FRM.
n/a	Balancing Authority lowest absolute Variable Bias Setting (least negative one minute average Bias while frequency is less than 59.964 or greater tha
	Enter Balancing Authority desired Bias Setting: May be set to a value between 100% to 125% of its FRM if this value is more negative than the minimu based on Peak Demand. If not more negative, then the Bias must be the minimum Bias based on Peak Demand. If variable Bias is used, enter "Va
-44.45	**2016 Frequency Bias Setting - (minimum of 100% to 125% of FRM, or 0.9% of Historical Peak Demand if not Variable)**
#DIV/0!	2016 FRM - Average Estimated Frequency Response MW/0.1 Hz using SEFRD for Bias
0.00	2016 FRM - Regression Estimated Frequency Response MW/0.1Hz using SEFRD for Bias
#DIV/0!	2016 FRM - Median Estimated Frequency Response MW/0.1Hz using SEFRD for Bias

- Clarified instructions for BA to desired Bias setting
  - 0.9% of aggregate Interconnection non-coincident peak demand from most recent FERC Form 714 (or equivalent) data reported, allocated by FRO allocation formula

    OR
  - 100% to 125% of BA's actual FRM performance from previous Operating Year

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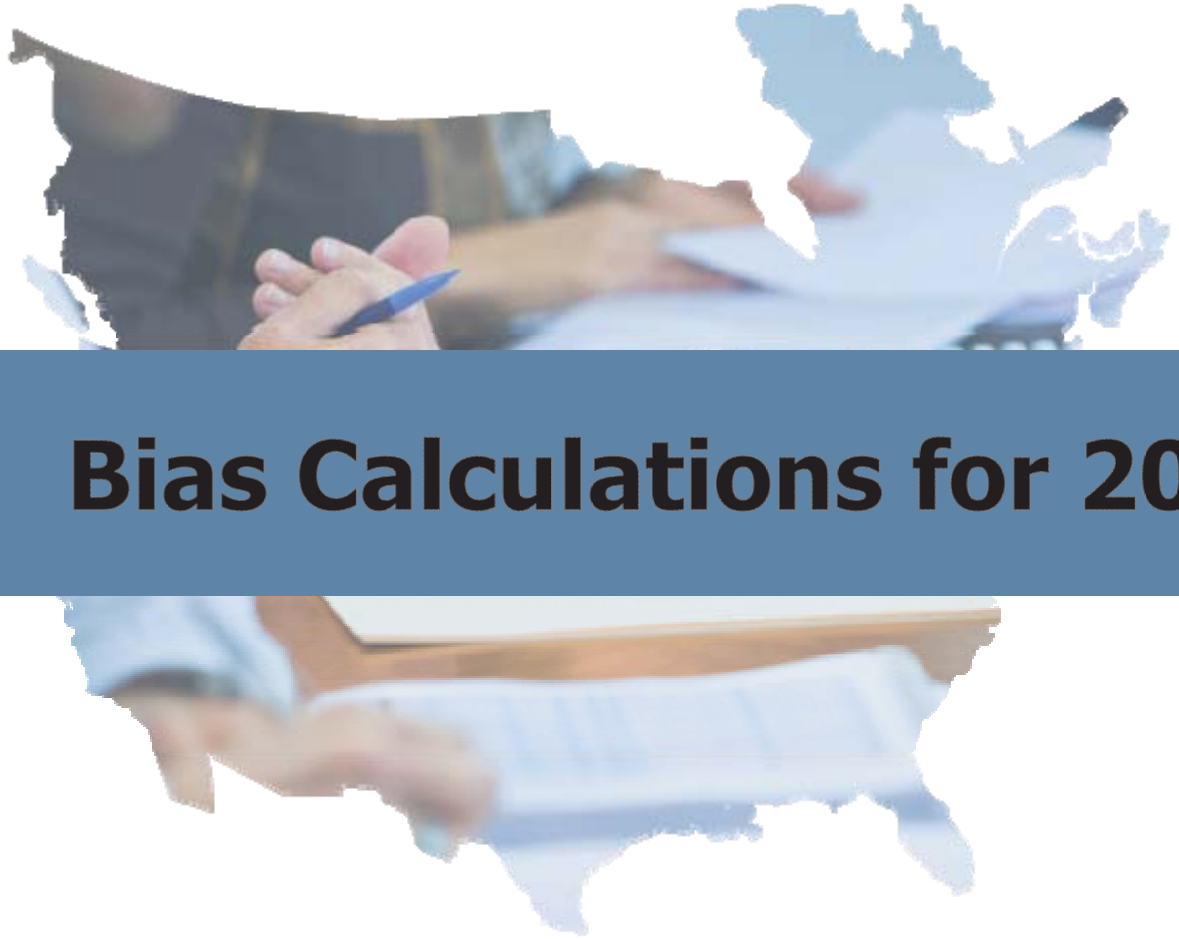

Bias Calculations for 2017

2017 Frequency Bias Settings and

- Revised FRS Forms will be issued in October-November 2016 timeframe with the BA FROs for 2017 Operating Year included
  - Will include 2015 FERC Form 714 demand and generation data
- FRS Forms 1 and 2 are to be submitted by March 7, 2017
- The ERO will then publish the final 2017 Frequency Bias Settings and L_{10} values in time for implementation on or about April 1, 2017
  - Posted on the BAS Site and sent to all BAS Site registered users
- 2017 Frequency Bias Settings will remain in effect from April 2017 through March 2018

2016 Frequency Bias Settings Posting

Eastern Interconnection

BA	Bias Type	Elected 2016 FBS	Receive Overlap Reg	Provide Overlap Reg	2016 L_{10}	2016 BA FRO
FMPP	Fixed	-27.07	N	N	35.52	-5.25
FPC	Fixed	-75.26	N	N	59.22	-14.59
FPL	Fixed	-195.18	N	N	95.37	-37.84
GVL	Fixed	-3.12	N	N	12.05	-0.60
HST	Fixed	-0.45	N	N	4.58	-0.09
JEA	Fixed	-21.04	N	N	31.31	-4.02
NSB	Fixed	-0.34	N	N	4.00	-0.07
SEC	Fixed	-10.42	N	N	22.04	-2.02
TAL	Fixed	-4.66	N	N	14.73	-0.90
TEC	Fixed	-33.65	N	N	39.60	-6.84
MHEB	Fixed	-58.73	N	N	52.32	-10.16
SPC	Fixed	-38.63	N	N	42.43	-7.49
IESO	Fixed	-245.52	N	N	106.97	-47.59
ISNE	Fixed	-195.79	N	N	95.52	-37.95
NYIS	Fixed	-251.98	N	N	108.36	-48.84
NBSO	Fixed	-35.87	N	Y	40.88	-8.77
NSPI	Fixed	-18.21	Y	N	29.13	-3.53
MISO	Fixed	-1,088.25	N	N	225.20	-210.95
OVEC	Fixed	-12.31	N	N	23.96	-1.93
PJM	Fixed	-1,332.53	N	N	249.20	-258.31
AEC	Fixed	-9.33	N	N	20.85	-1.81

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BAL-003-1 Implementation Workshop

Salt Lake City, UT.

Tony Nguyen – BC Hydro
NERC RS Frequency Working Group - Chair
August 23, 2016

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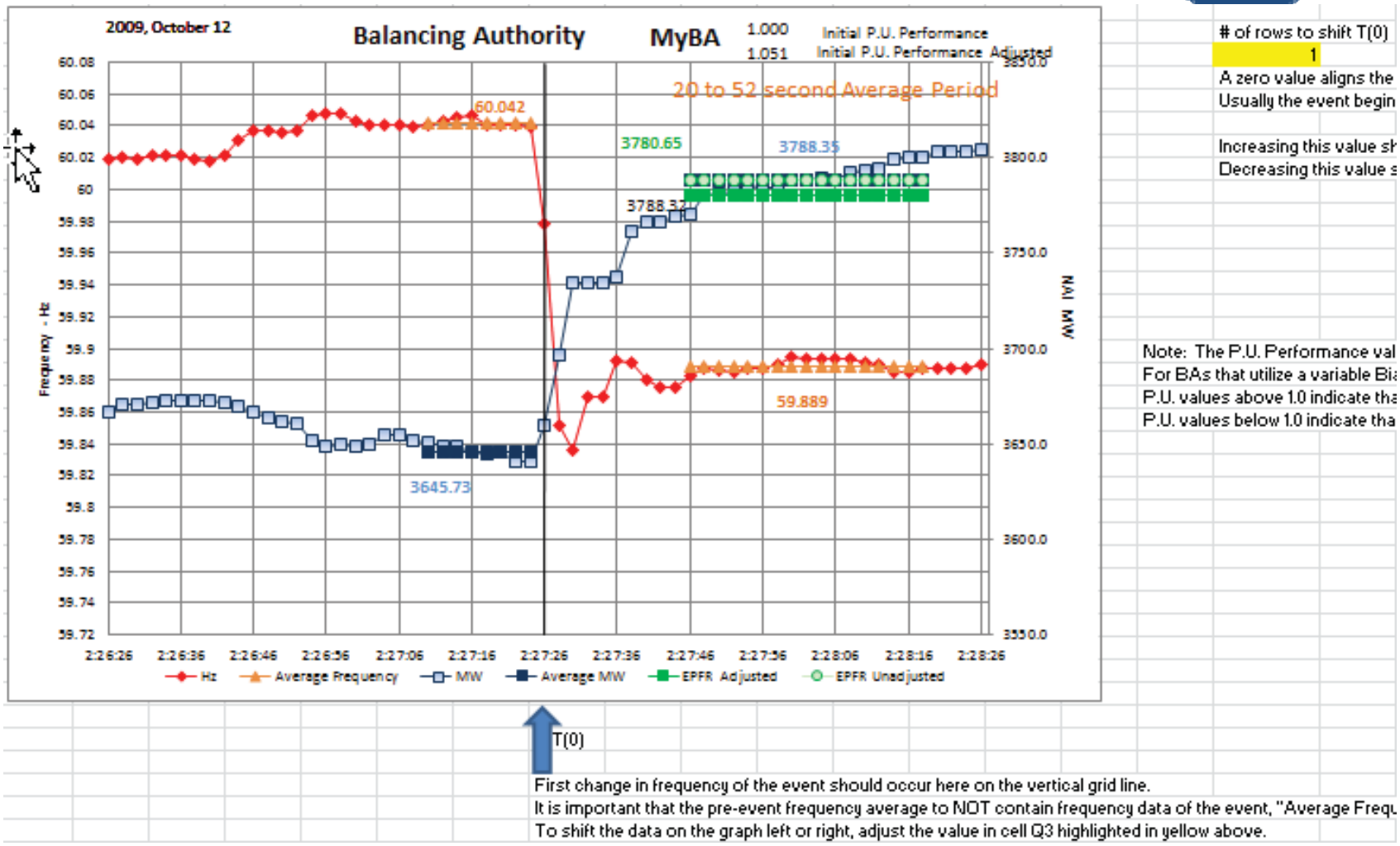
Event Reporting Problems and Solutions

Lining up BA's frequency with event times



- Form 2: T(0) should be at the first significant frequency drop

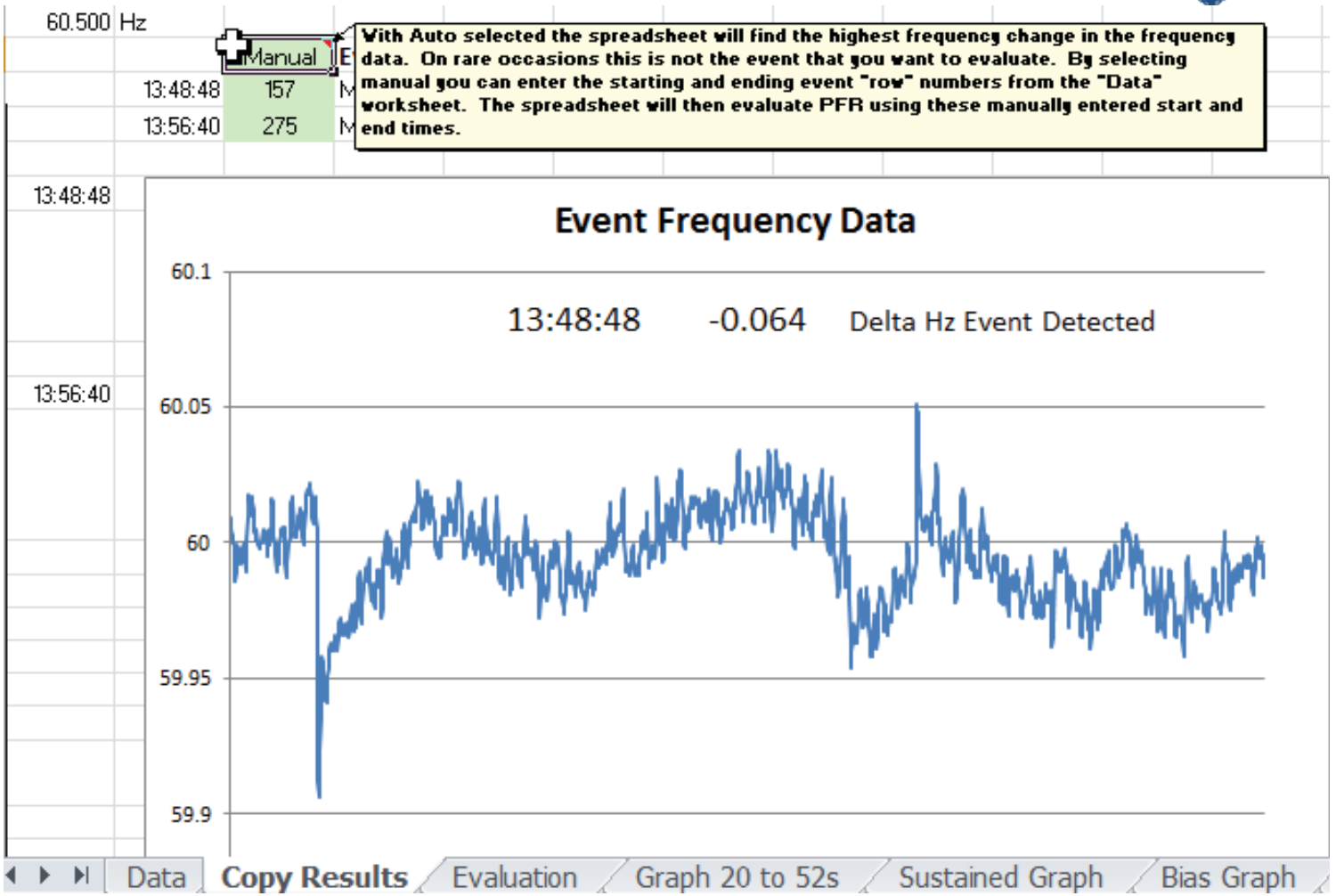
Lining up BA's frequency with event times

Date/Time (t-0) (Central Prevailing)	Time Zone	Date/Time (t-0) BA Time	BA Time Zone	DelFreq	BA Time	BA Bias DelFreq	Relay Lmt R1 DelFreq	Value "A" Information NAI	Adjustment
12-10-2014 18:30:16	CST	12-10-2014 16:30:16	PST	-0.039	16:30:20	-0.041	-0.041	-397.0	0.0
12-28-2014 7:12:31	CST	12-28-2014 5:12:31	PST	-0.058	5:12:35	-0.059	-0.059	-187.0	0.0
12-29-2014 16:03:58	CST	12-29-2014 14:03:58	PST	-0.091	14:03:58	-0.096	-0.096	-540.3	0.0
1-21-2015 4:51:53	CST	1-21-2015 2:51:53	PST	-0.085	2:51:57	-0.087	-0.087	165.5	0.0
1-21-2015 5:23:23	CST	1-21-2015 3:23:23	PST	-0.063	3:23:27	-0.064	-0.064	48.5	0.0
2-17-2015 11:14:00	CST	2-17-2015 9:14:00	PST	-0.046	9:14:04	-0.047	-0.047	-400.6	0.0
3-3-2015 16:24:52	CST	3-3-2015 14:24:52	PST	-0.050	14:24:52	-0.053	-0.053	90.7	0.0
3-28-2015 16:15:25	CDT	3-28-2015 14:15:25	PDT	-0.065	14:15:29	-0.064	-0.064	-1465.6	0.0
3-29-2015 15:48:44	CDT	3-29-2015 13:48:44	PDT	-0.062	13:48:48	-0.064	-0.064	-789.4	0.0
4-5-2015 14:57:54	CDT	4-5-2015 12:57:54	PDT	-0.059	12:57:54	-0.062	-0.062	78.9	0.0
5-3-2015 6:39:47	CDT	5-3-2015 4:39:47	PDT	-0.051	4:39:51	-0.053	-0.053	1836.8	0.0
5-12-2015 12:41:10	CDT	5-12-2015 10:41:10	PDT	-0.036	10:41:14	-0.036	-0.036	1354.1	0.0
5-28-2015 16:37:06	CDT	5-28-2015 14:37:06	PDT	-0.037	14:37:06	-0.044	-0.044	1545.9	782.0
6-22-2015 17:12:03	CDT	6-22-2015 15:12:03	PDT	-0.047	15:12:07	-0.046	-0.046	1526.0	0.0
7-1-2015 9:14:41	CDT	7-1-2015 7:14:41	PDT	-0.060	7:14:45	-0.061	-0.061	569.0	0.0
7-10-2015 5:03:29	CDT	7-10-2015 3:03:29	PDT	-0.058	3:03:29	-0.060	-0.060	-43.9	0.0
7-10-2015 18:58:10	CDT	7-10-2015 16:58:10	PDT	-0.083	16:58:10	-0.084	-0.084	744.4	1284.0
7-26-2015 12:25:25	CDT	7-26-2015 10:25:25	PDT	-0.066	10:25:29	-0.064	-0.064	-313.3	0.0
8-4-2015 21:07:19	CDT	8-4-2015 19:07:19	PDT	-0.065	19:07:19	-0.067	-0.067	1322.5	0.0
9-1-2015 12:30:13	CDT	9-1-2015 10:30:13	PDT	-0.064	10:30:13	-0.066	-0.066	915.0	0.0
9-3-2015 9:48:20	CDT	9-3-2015 7:48:20	PDT	-0.056	7:48:20	-0.058	-0.058	1371.5	0.0
9-5-2015 9:25:12	CDT	9-5-2015 7:25:12	PDT	-0.109	7:25:16	-0.109	-0.109	-160.4	0.0
10-9-2015 14:08:32	CDT	10-9-2015 12:08:32	PDT	-0.065	12:08:32	-0.070	-0.070	383.6	0.0
10-30-2015 10:35:13	CDT	10-30-2015 8:35:13	PDT	-0.057	8:35:17	-0.058	-0.058	331.5	0.0
11-8-2015 15:14:47	CST	11-8-2015 13:14:47	PST	-0.073	13:14:51	-0.074	-0.074	-871.3	0.0

- Form 1

Should be closely matched

Lining up BA's frequency with event times



- If not matched: manually select event time in Form 2.

Synchronization of tie line data and frequency data

- BA may receive data from many entities
- It's important to have all related data synchronized with the same time stamp
- Latent time in data scanning, processing, transmitting and recording should be compensated for
- Suggestion / Discussion:
  - Sender to have local frequency data sent with tie line data (and other related data such as shares of JOUs),

    then
  - Receiver can realign data by comparing frequency trends.

Other Reporting Problems - open discussion

- Handling of Adjustment for JOU Dynamic Schedules
  - Optional, not mandatory. If chosen, must do for all events.
  - May help or hurt frequency response measure
  - Timing of recalculation of shares of jointly-owned-units
  - Potential double counting?
- Handling of Contingent BA Adjustment for JOUs that tripped.
  - Applied only when JOU is part of the contingency
  - Should always help frequency response measure
- Data storage and compression issues
- Frequency of data submittal – annual versus quarterly

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Mechanics of Frequency Response Sharing Groups

Don Badley
Northwest Power Pool
NERC Resources Subcommittee
August 23, 2016

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Mechanics of Frequency Response Sharing Groups - Definitions

- **Frequency Response Sharing Group** (FRSG): A group whose members consist of two or more Balancing Authorities
- **Frequency Responsive Reserve**: An amount of reserve automatically responsive to locally sensed frequency deviation.
- **Agreement:** A contract or arrangement, either written or verbal and sometimes enforceable by law. For our purposes – an Agreement is a document indicating the formation of a FRSG (Refer to the Operating Reserve Management Guideline)

Mechanics of Frequency Response Sharing Groups – The Agreement

FRSGs should have a formal agreement among its members in place prior to registration. The FRSG agreement among the participant responsible entities for the FRSG should address the following:

- Identification of designated representative (Agent)
- Minimum frequency-responsive (F-R) reserve requirement for the group
- Reporting, record keeping, and accountability for regulatory compliance
- Each member's portion of the total F-R reserve requirement
- Methodology used to calculate the member's F-R reserve responsibility
- How information is shared among members in Real-time
- Tools for operators to have situational awareness of F-R Reserve of the FRSG

Mechanics of Frequency Response Sharing Groups – FRSG Agent

- Designated Representative (Agent) - an entity that will provide the necessary information and compliance reports for the group.
  - Identifies the make up of the FRSG (listing of the participating BAs) to the compliance authority of the FRSG (i.e., Registration)
  - Must have access to all the data needed for the FRSG performance analysis.

Mechanics of Frequency Response Sharing Groups – The Term

- FRSGs should be pre-arranged and member participation should coincide with the BAL-003 operating year (December 1 through the following year November 30).
- Any member BA's minimum period of participation should be one (1) BAL-003 operational year.
- Partial BAL-003 operating year participation should not be allowed.
- Per event participation with other BAs is a bi-lateral transaction and is not considered an FRSG. Like bi-lateral transactions, FRSGs can only be established prior the analysis period.
- No BA may be a member of more than one FRSG at any given time.

Mechanics of Frequency Response Sharing Groups – Performance

Performance measurement FRSG - two methods

1. Determining the sum, for each compliance measured event of the FRSG BAs (sum of the FRSG BAs FRS Form 1 and FRS Form 2) and then designating the median Frequency Response Measure for the FRSG as the median of the sums, or
2. Measurement of the FRSG for each compliance measured event and then designating the median Frequency Response Measure for the FRSG as the median of the measurement.

Mechanics of Frequency Response Sharing Groups – References

Reliability Guideline: Operating Reserve Management

http://www.nerc.com/comm/OC/Reliability%20Guideline%20DL/Operating_Reserve_Management_Guideline_20131018_Final.pdf

Standard BAL-003-1.1

http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=BAL-003-1.1&title=Frequency Response and Frequency Bias Setting&jurisdiction=United States

FERC Final Order on Third-Party Provision of Primary Frequency Response Service - FERC Docket RM15-2-000 Order No. 819

http://www.ferc.gov/whats-new/comm-meet/2015/111915/E-1.pdf

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BAL-003-1 Implementation Workshop

Salt Lake City, UT

Robert W. Cummings
Senior Director of Engineering & Reliability Initiatives
August 23, 2016

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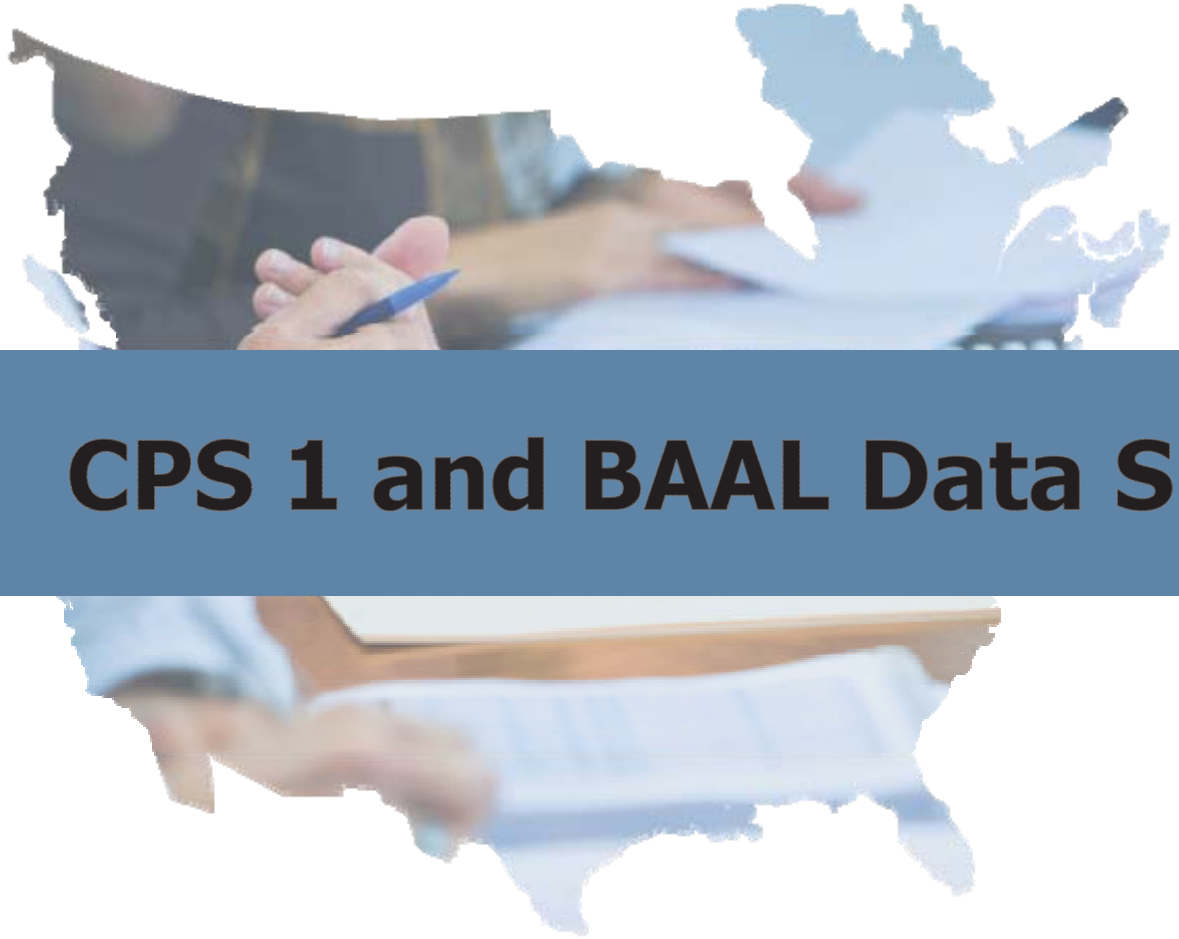
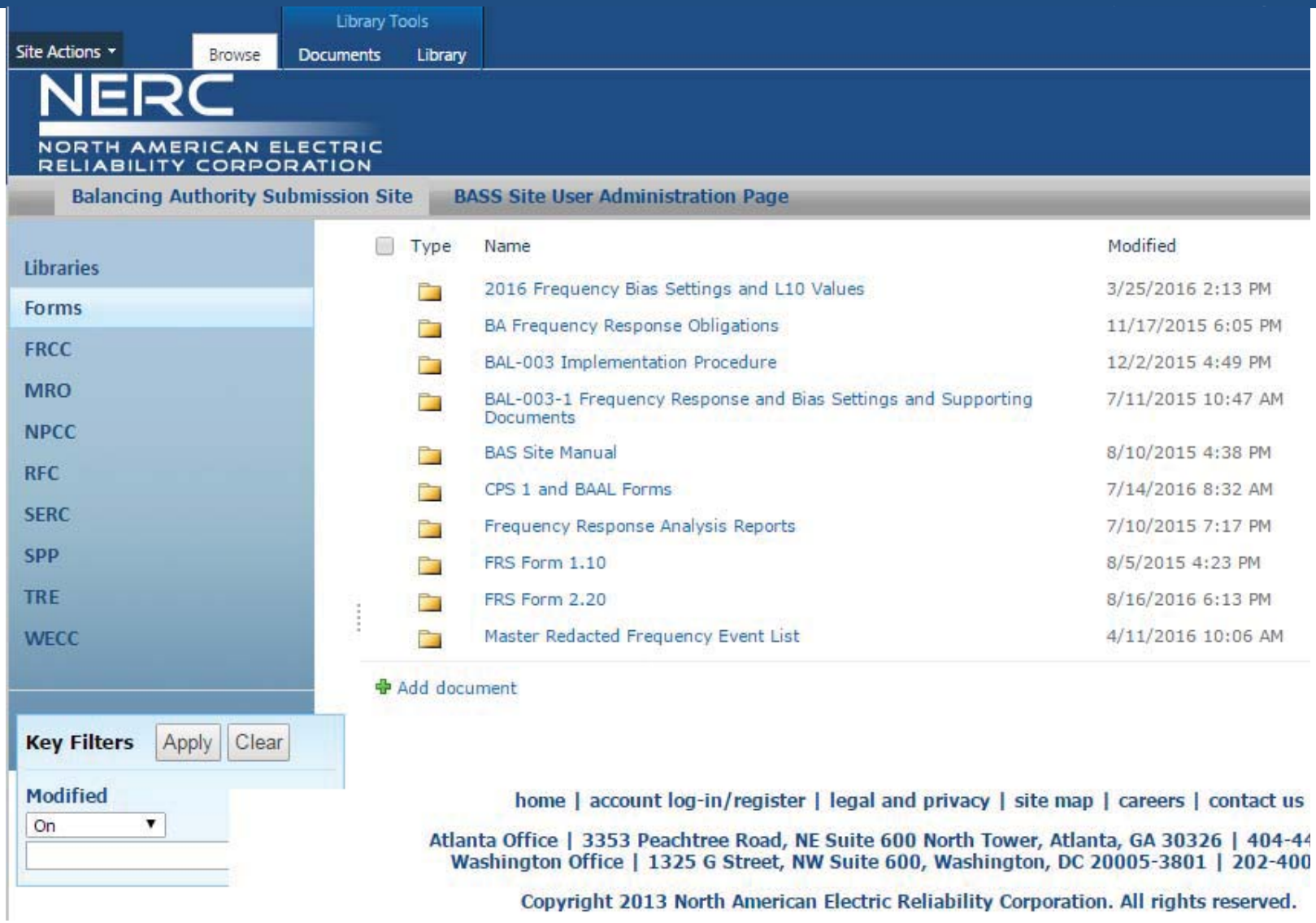


CPS 1 and BAAL Data Submittal

CPS1 & BAAL Data Collection

- CPS1 and BAAL exceedance data needed for Resources Subcommittee to analyze performance under BAL-001-2
- FERC Order on BAL-001-2requires NERC to submit an informational filing on performance
- Requested by Operating Committee Jim Case in a letter of May 19, 2016
- Data to be reported quarterly, starting in October for 2016 Q3 (July through September)
- Submittal form and instructions posted on BAS Site under forms

BASS Forms Content



CPS1 & BAAL Submittal Form

CPS1 and BAAL Exceedance Data*

Submitter's Contact Information

Technical Contact Name	Email	Telephone	Date Submitted (mm/dd/yyyy)
			10/1/2016

Reporting Period	July-September			
Select Interconnecton	Western	Select BA		

Data Coordination (if applicable)

OUR DATA HAS BEEN COORDINATED WITH AND IS COVERED BY ANOTHER PARTY			Yes
Select Coordinating Entity	Contact Name	Telephone	Email

CPS1 Data Entry

	July	August	September
CPS1 Monthly Percentage			
CPS1 Rolling 12 Month Percentage			
Clock-Minutes CPS1 <-700% (Optional)			

BAAL Data Entry

	July	August	September	Quarterly Total
10-14 Minute Exceedance				0
15-19 Minute Exceedance				0
> 20 Minute Exceedance				0
BAAL Clock-Minute Exceedances (Optional)				0

* These data are being collected from Balancing Authorities to support the Resources Subcommittee with their task of evaluating interconnection reliability related to control performance, and providing FERC with the analysis requested in FERC Order No. 810. These data were requested by Operating Committee Chairman Jim Case in his letter of May 19, 2016. **NERC will disclose this information only as required and in accordance with the procedures pursuant to Section 1500 of the NERC Rules of Procedure.**

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Balancing Authority Submittal Site (BASS)

Balancing Authority Submittal Website

- Private Secured SharePoint Site for BAL data submittals
- Individual NERC ID-level users
- Common area for:
  - Current FRS Forms & instructions
  - Frequency Events lists and related data
  - Other related information
- Exclusive BA-level submittal areas
- User's guide at:

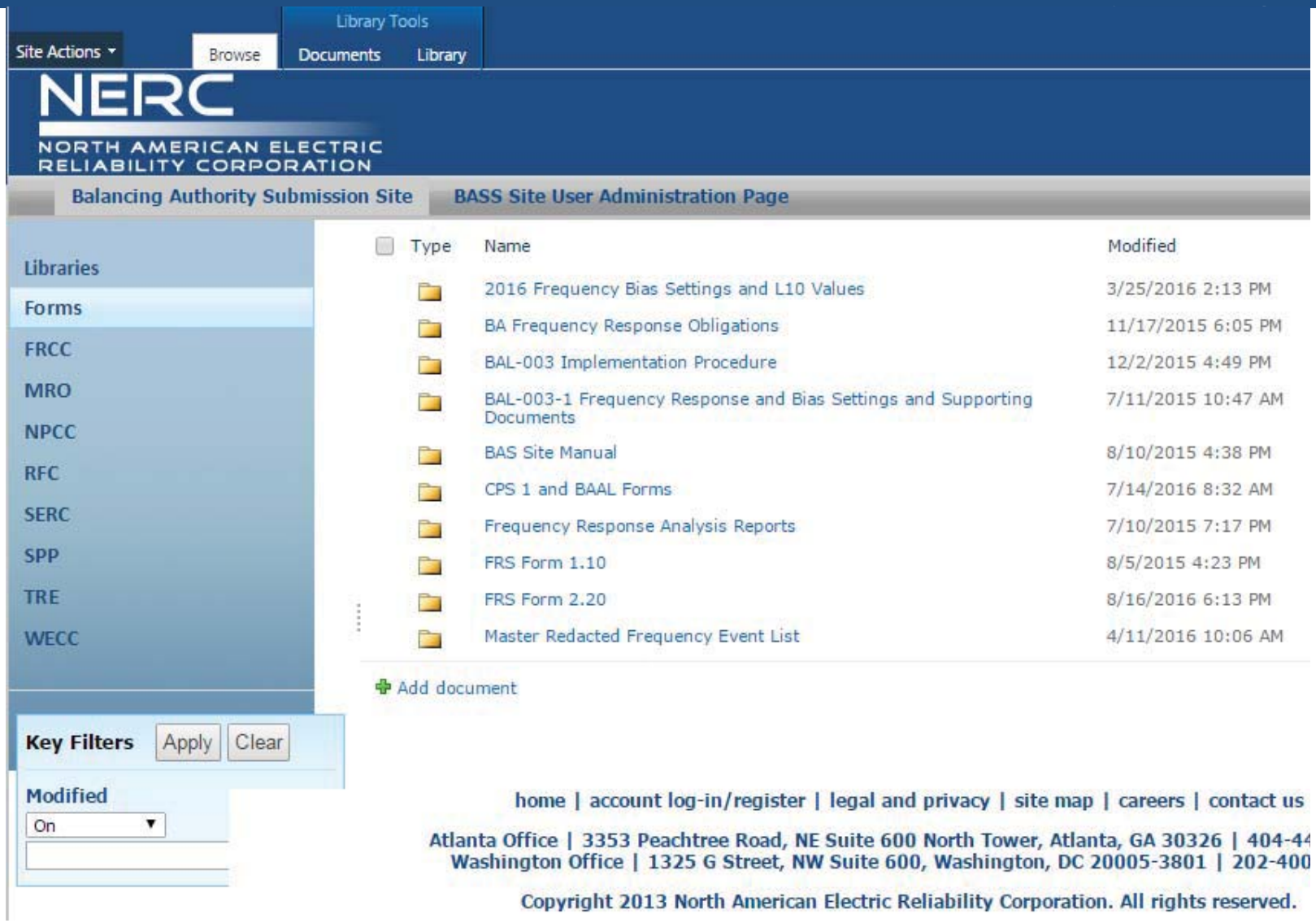
  http://www.nerc.com/comm/OC/Related%20Files%20DL/BASS_User_Manual_v1.0_October_2015.pdf

Balancing Authority Submittal Website

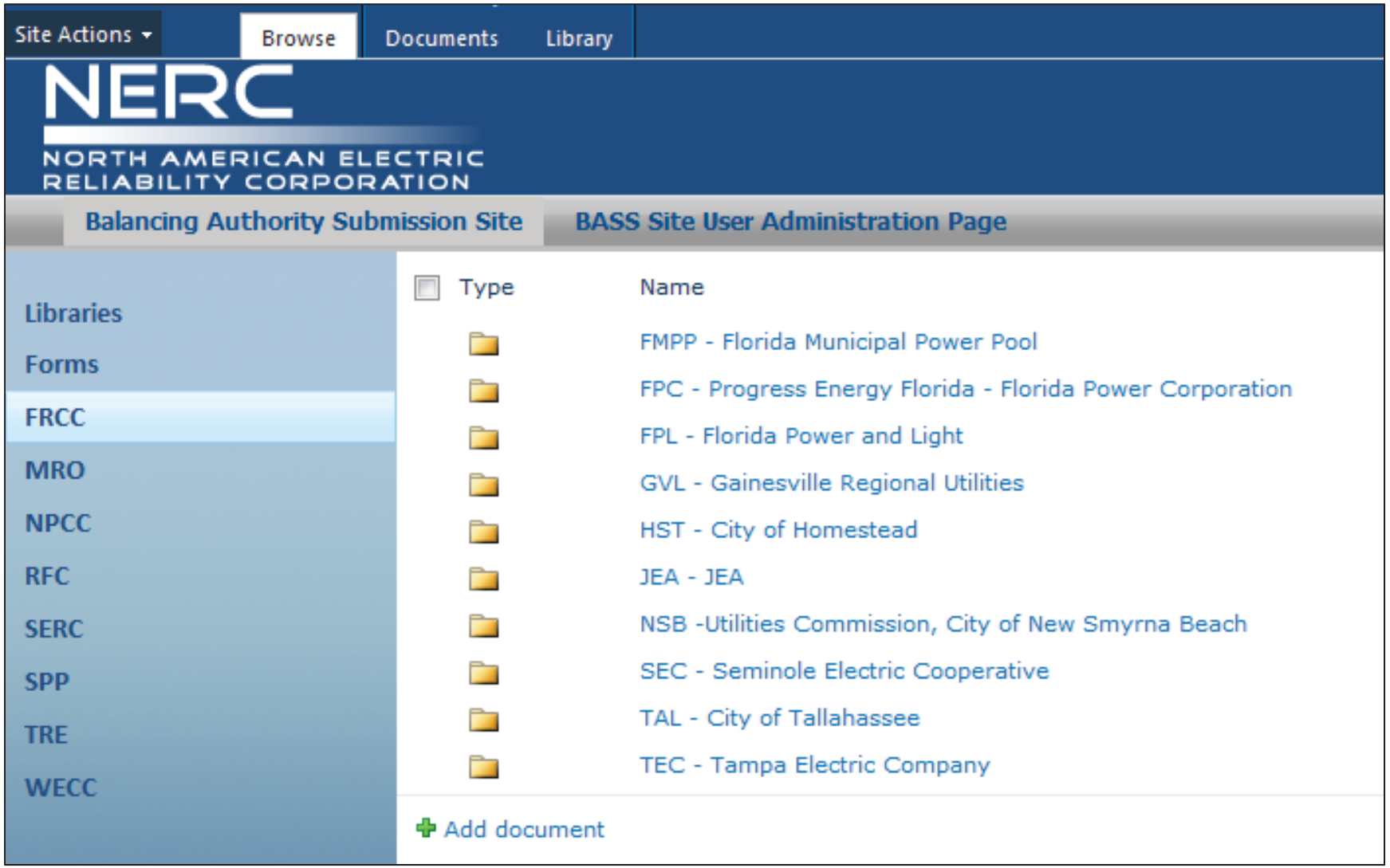
User Roles and Capabilities

- BA Users – Users from each BA will download forms and upload their data to their own exclusive area
  - Able to read and download forms from common area
  - Read, Write, delete for their BA only
  - Cannot look at data from other BAs
- FWG/RS Users – Members of the NERC Frequency Working Group and the Resources Subcommittee
  - All members have signed non-disclosure agreements
  - Capabilities – Read and download data from all files for performance analysis
- NERC Staff – Administrator / Vetting
  - Complete visibility and administrative control

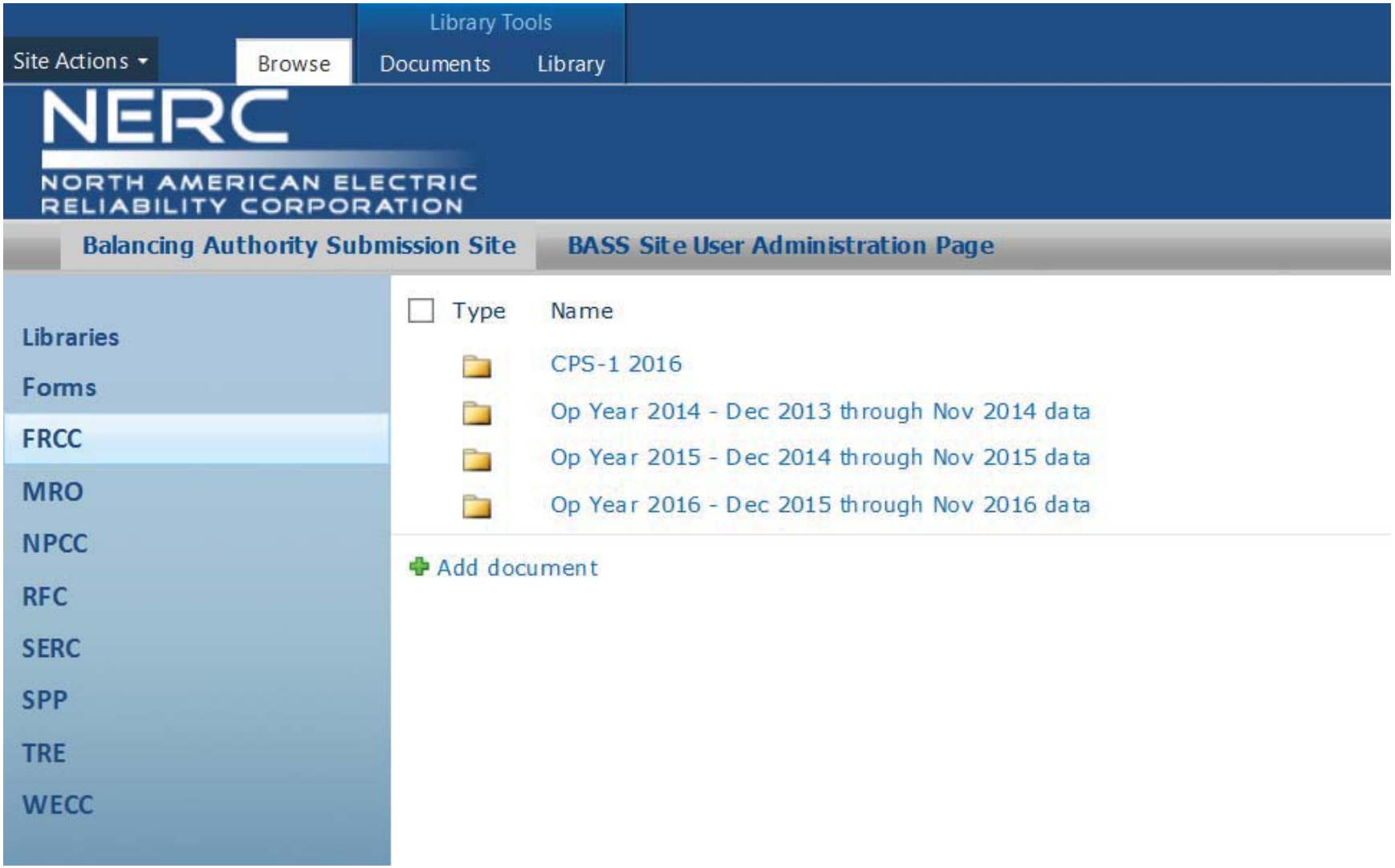
BASS Forms Content



BASS Layout Regional Example



BASS Layout Regional Example



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