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NORTH AMERICAN ELECTRIC
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Primary Frequency Response – Natural Gas/Combined Cycle Webinar

November 13, 2018

RELIABILITY | ACCOUNTABILITY




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Survey Participation Request

Eastern Interconnection Generator Operator Survey

To: Eastern Interconnection Generator Operators:

The Eastern Interconnection (EI) representatives from the NERC Resources Subcommittee request your participation in an event survey. The event selected for the survey occurred in the EI on November 20, 2017 at 16:12:15 EST (11/20/2017 21:12:15 UTC). The approximate generation loss was 852 MW.

This survey is an industry lead effort to gather information to address reliability issues regarding frequency response, and has been endorsed by the NERC Operating Committee and the North American Generator Forum. As this survey is voluntary, it is being requested that every Generator Operator participate to demonstrate, as an industry, that reliability issues can be addressed outside of mandatory requirements. To participate in the survey, please review the attached documents and submit the spreadsheet with the requested information to FrequencyEventData-EI@nerc.net **by January 12, 2018.**

For questions regarding how to use the spreadsheet, please contact David Deerman (via email) for assistance. For general questions about the survey, please contact Troy Blalock (via email).

For additional reference, the presentation and streaming webinar from the November 14, 2017 Eastern Interconnection Generator Operator webinar have been posted on the NERC website and can be accessed at the links below.

Click here for: Presentation | Streaming Webinar

For more information or assistance, please send an email to FrequencyEventData-EI@nerc.net.

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Atlanta, GA 30326
404-446-2560 | www.nerc.com

THE UNIVERSITY OF TENNESSEE KNOXVILLE

FNET GridEye

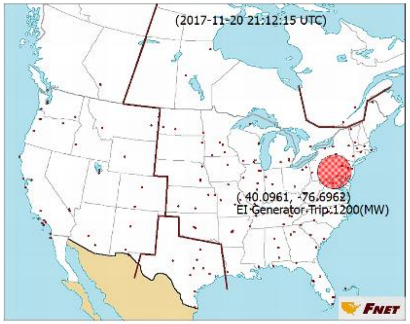
OAK RIDGE National Laboratory

FNET Event Report

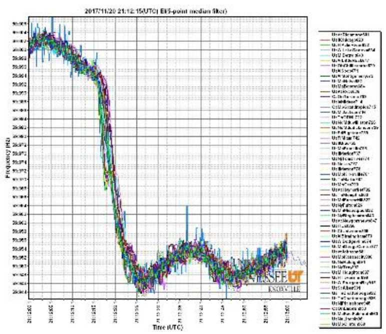
Basic Event Information

Event Date	Event Time	Event Type	Estimated Amount
2017-11-20	21:12:15 UTC	Generation Trip	1200 MW
Point A	Point B	Point C	Point C Prime
59.9965 Hz	59.9511 Hz	59.9465 Hz	59.9455 Hz
MOD-027-1 Event	Inter Connection	Estimated Reliability Coordinator	ROCOF
NO	EI	RFC	8.21 mHz/s
Estimated Event Location		Additional Location Information	
(40.0961, -76.6962)		near Brunner Island power plant (RFC) in (York Haven,PA,17370).	

Location Map



Frequency Plot of All FDRs



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Eastern Interconnection

Eastern	Interconnection	SMILEY FACES	FROWNY FACES	UNITS at PMAX
Event ID:	EI_2017-11-20_211215	☺	☹	
Event Date & Local Time:	11/20/2017 21:12:15	213	526	11

Combustion Turbine - Combined Cycle
Steam Turbine - Coal Fired
Steam Turbine - Coal Fired
Steam Turbine - Coal Fired
Steam Turbine - Coal Fired
Steam Turbine - Coal Fired
Steam Turbine - Coal Fired
Steam Turbine - Coal Fired
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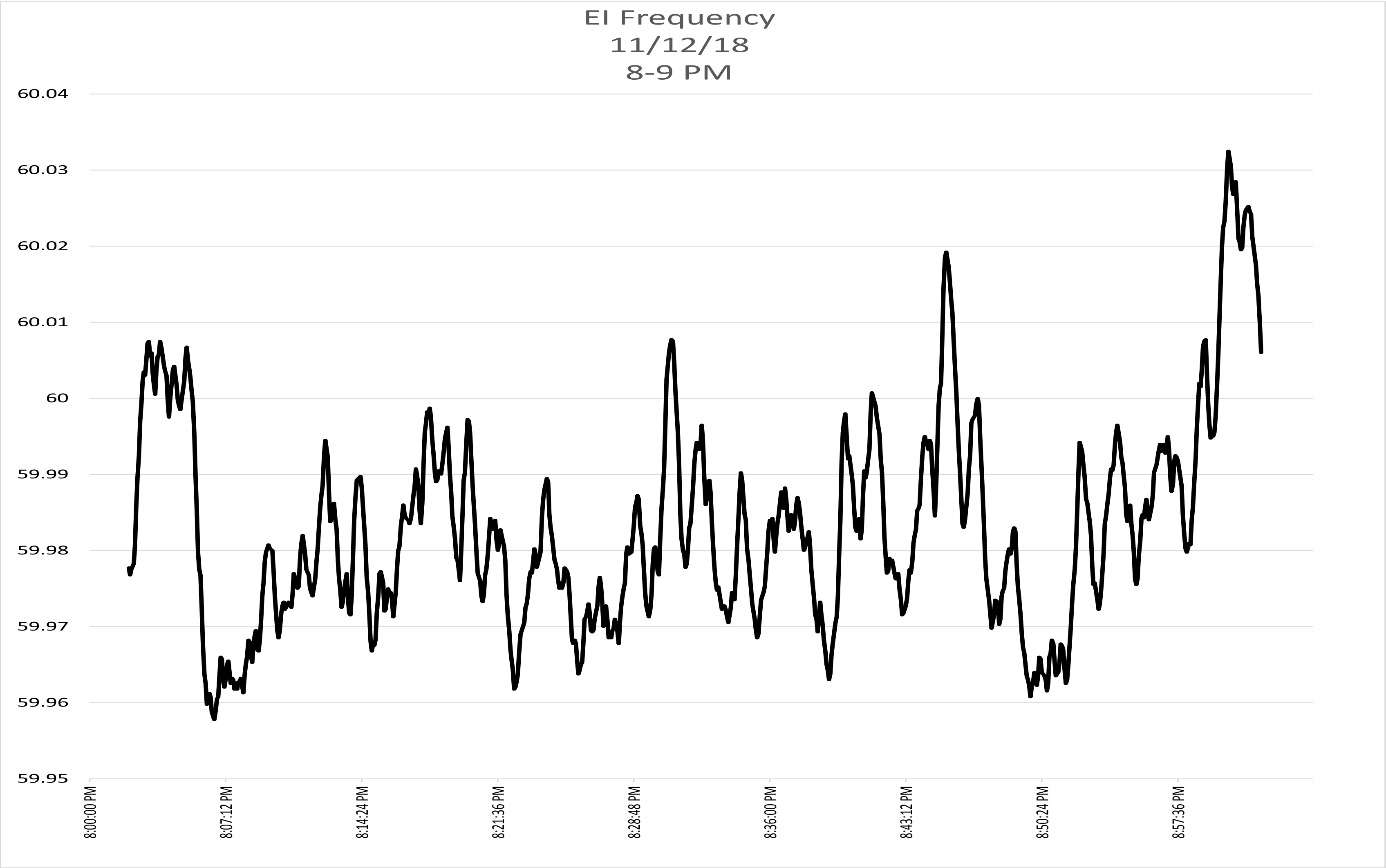
Steam Turbine - Coal Fired
Steam Turbine - Coal Fired
Steam Turbine - Coal Fired
Steam Turbine - Combined Cycle
Combustion Turbine - Combined Cycle
Combustion Turbine - Combined Cycle
Steam Turbine - Coal Fired
Wind
Steam turbine-Coal fired
Combustion Turbine - Combined Cycle
Combustion Turbine - Combined Cycle
Combustion Turbine - Combined Cycle
Combustion Turbine - Combined Cycle
Steam Turbine - Combined Cycle
Steam Turbine - Combined Cycle

750 Online BES Generators responded to the Survey

Summary:

1) Outer Loop Controls preventing or squelching #1 issue.
2) GO understanding of PFR and GO data quality

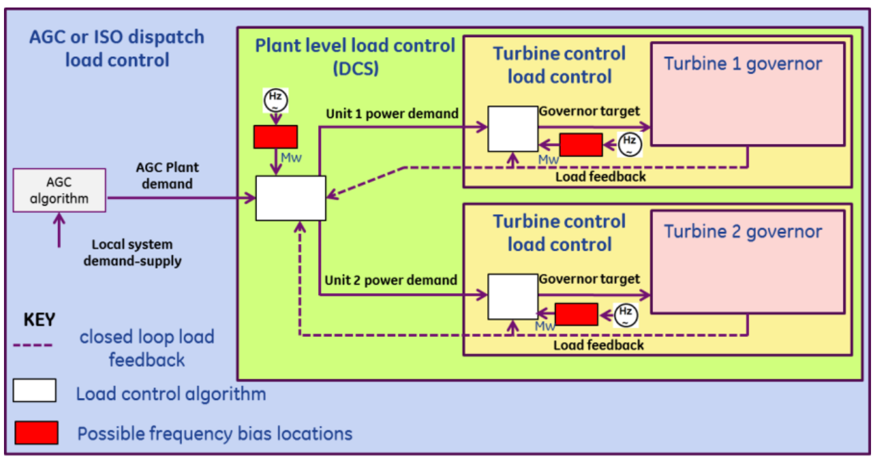
Frequency


EI Frequency
11/12/18
8-9 PM
60.04
60.03
60.02
60.01
60
59.99
59.98
59.97
59.96
59.95
8:00:00 PM
8:07:12 PM
8:14:24 PM
8:21:36 PM
8:28:48 PM
8:36:00 PM
8:43:12 PM
8:50:24 PM
8:57:36 PM

Primary frequency response - GE

Communications

- Gas Turbine PSIB 20150203
  - Focuses on PFR at plant level
- Steam turbine TIL-1961-R1
  - Deadband checks / recommendations



Example control loop hierarchy

Notable issues

- Few recent questions
- PFR should be implemented at highest plant level closed loop load control and coordinated as needed inside the outer loop
- Disabling load control or AGC outside dead band sometimes done to “free “ governor ….but this disables correction of frequency / ACE by AGC
- Signal resolution of frequency signal matters. Turbine speed typically highest resolution, check frequency meter resolution if used
- Renewable push demand for speed of primary response in some global markets

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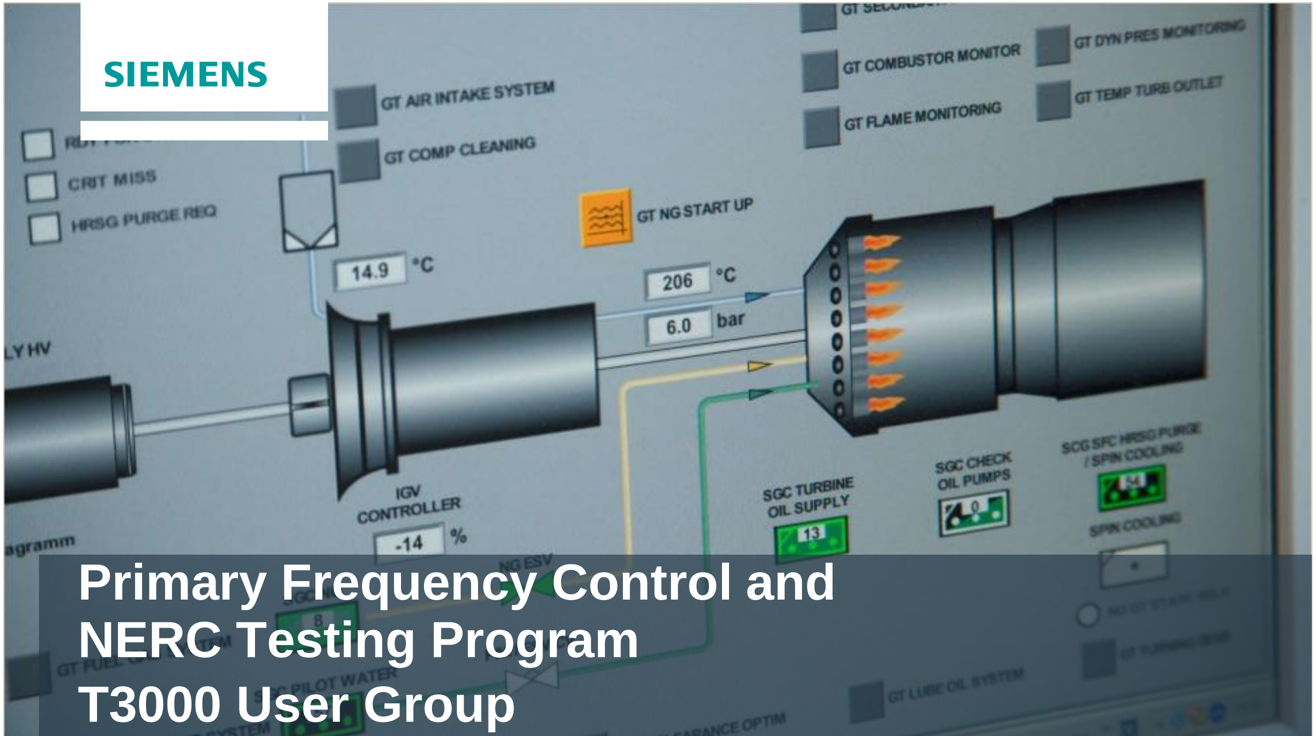

Primary Frequency Control and NERC Testing Program
T3000 User Group

May, 2015

Frequency Regulation: See NERC Alerts
Eastern Interconnection Frequency Initiative Whitepaper. Copied from NERC website

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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 60Hz.

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Customer Reference 2015-001

NERC Alert
Generator Governor Frequency Response

Program Areas & Departments > Reliability Risk Management > Bulk Power System Awareness > Alerts

Alerts

To acknowledge, respond to, or approve of an alert, please click here.

2015 Alerts		
Date	**Description**	**Responsible Entities**
02.05.15	**Industry Advisory:** Generator Governor Frequency Response Eastern Interconnection Frequency Initiative Whitepaper Frequency Response Initiative Report	Balancing Authority, Generator Owner, Generator Operator, Reliability Coordinator, Resource Planner, Transmission Operator, Transmission Planner

NERC Alert

Generator Governor Frequency Response

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Initial Distribution: February 5, 2015

Advisory: With exception of nuclear generators, all recipients of this Advisory with generating resources with gross plant / facility aggregate nameplate rating greater than 75 MVA should review generator governor and Distributed Control System (DCS) settings and ensure that, in the absence of technical or operational considerations, dead bands do not exceed **+/- +-36 mHz, droop setting does not exceed 5%,** and that governors are coordinated with the DCS at the generating unit or plant level to provide frequency response.

A growing number of generator governor controls are contained in the associated turbine control system. Typically these functions are referred to as speed control, and reference turbine speed in revolutions per minute (rpm). Entities should review these turbine controls and settings to ensure they are providing the desired governor response with a maximum +-36 mHz deadband and a droop characteristic not exceeding 5%. **As generator deadband and droop settings are determined or modified, Generator Owners and Operators should communicate those settings and other important governor control system data to their Balancing Authority and Transmission Planning Authority**.

Primary Frequency Control
What does NERC want?

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- NERC wants to reduce the deadband to Ercot Levels (+-17 mHz) in the future
- A linear droop with no step at the deadband edges.
- Droop gradient stays at 5%. It is known to NERC that the deadband distorts this slightly.
- Best practice is to get the effective primary frequency correction from the turbine governors and pass this up to the plant controller.
- Siemens would assist in redesigning the plant master controller to incorporate primary frequency. See Siemens advisory
- CT default deadband of +-36 mHz.
- CT default droop to 5% or less. Standard 4%
- No time response specified
- The regional balancing authority will specify exact details

SIEMENS

CCPP

- CTs Droop 4%, Deadband +-36 mHz,
- ST 5%, +-36 mHz (Overall 5.78%) same as Ercot desirable.
- No time response specified. Refer to BA

Ercot per BAL-001-TRE-1 for CCPP's

- CTs Droop 4%, Deadband +-17 mHz
- ST Droop 5%, deadband +-17 mHz.
- Exception per operating conditions according to R9.3 and R10.3 is possible
- CCPP overall response 5.78% is required. Dependent on ST response and efficiency. See example
- 16 seconds 70% and response maintained up to 46 seconds is the time line specified.(Test spec. Ercot Nodal Operating Guide)
- Response performance of 0.75 rolling average or better is required
- Test +-0.2 Hz

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Grid Primary Frequency Control a NERC Concern An Advisory Document in Support of NERC Alert A- 2015-02-05-01

http://wwwnerccom/pa/rrm/bpsa/Pages/Alertsaspx

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Customer Reference 2015-001

Primary Frequency Control
Energy (Battery) Storage Driven.

Basic System

- Battery
- Bidirectional Inverter
- RegD interface
- Monitoring and control system

Primary Frequency Control use cases,

- Removal of reserve
- Regulation Markets PJM and California CASIO (AB-2514 Energy storage systems)

Siemens provides turnkey projects.

ROI 3 to 4 years in most cases

Load Shifting with stored energy is another compelling business case.

NERC Testing Program
Presented in this slide set

SIEMENS

MOD-27-1

- Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions,

MOD-25-2

- Verification and Data Reporting of Generator Real and Reactive Power Capability

MOD-26-1

- Verification of Models and Data for Generator Excitation Control System or Plant Volt/VAR Control Functions
- **PSS Model** Verification of Models for the Power System Stabilizer (PSS)
- **AVR and PSS Tuning** to meet specific NERC regions' requirements

NERC Testing Program
Also coming up

MOD-32

- Supply of steady-state, dynamics, and short circuit modeling data for Power System Modeling and Analysis.

PRC-19

- Verification of coordination of plant capabilities, voltage regulating controls and protection system settings.

PRC-24

- Verification of generator frequency and voltage protective relays settings – relay/ AVR limiter coordination.

MOD-27
Turbine/Governor and Load Control or
Active Power/Frequency Control Functions

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Purpose:

To verify that the turbine/governor and load control or active power/frequency control 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.

Applicable to:

Conventional synchronous generation.

Active power/frequency control applies to inverter connected generators.

Unit Size and Type	Generation MVA. Gross Nameplate		
	Eastern Interconnection	Western Interconnection	Ercot
Individual Units	> 100 MVA.	> 75 MVA	> 50 MVA
Generating plant. Total Generation goss aggregate nameplate	> 100 MVA	> 75 MVA	> 75 MVA

MOD-27
Verification

SIEMENS

Verification is by test or from operational data

Documentation comparing the applicable unit's MW model response to the recorded MW response for either:

- A frequency excursion from a system disturbance that meets MOD-027 Attachment 1 with the applicable unit on-line,
- A speed governor reference change (test) with the applicable unit online,
- A partial load rejection test,

The units MW response can be compared to a model simulation or a model with new parameters can generated from the plant MW responses.

MOD-27
Documentation

Documentation: Per attachment 1:

- Initial verification: Transmit the verified model, documentation and data to the Transmission Planner on or before the Effective Date.
- Subsequent verification: Transmit the verified model, documentation and data to the Transmission Planner on or before the 10-year anniversary of the last transmittal
- Representation of the real power response effects of outer loop controls (such as operator set point controls, and load control but excluding AGC control) that would override the governor response (including blocked or nonfunctioning governors or modes of operation that limit Frequency Response),
- Other plant data

MOD-27
Timeline

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Enforcement Dates

- R1, R3, R4 and R5 - 07/01/2014

Enforcement dates for R2 (verification)

- 30 % for each Interconnection - 7/1/2018
- 50 % for each Interconnection - 7/1/2020
- 100 % for each Interconnection - 7/1/2024
- Reoccurrence every 10 years
- Changes to the turbine/governor and load control or active power/frequency control system
  - provide revised model data or plans to perform model verification to the Transmission Planner within 180 calendar days of making changes

A copy of MOD 27-1 can be handed out or refer to the NERC website

MOD-27-1
Governor Control Systems Models Verification
Siemens Services

SIEMENS

On site testing or operational data extraction per MOD 27-1

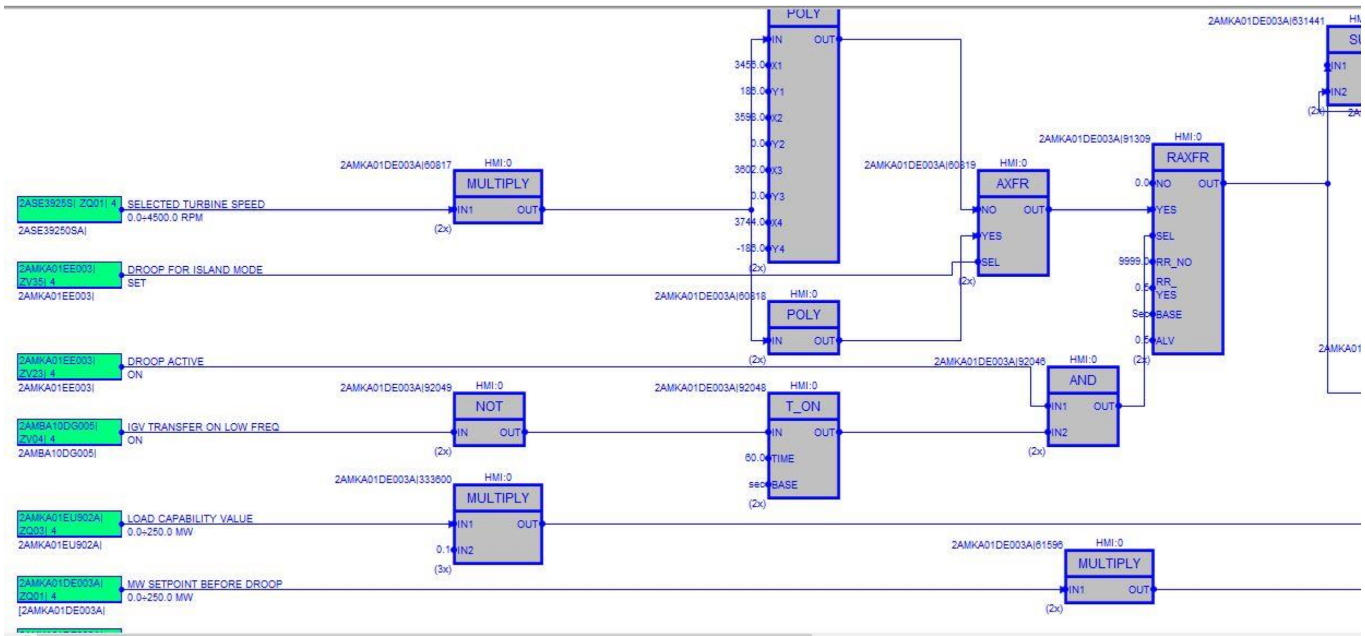
- Perform testing and/or record data to provide data on the response dynamics of the governor on-line
- The step at the speed reference will be applied by Siemens.

Data Analysis Services

- Data processing for field measurements & records
- Validating the current PSS®E dynamic models
  - Model is validated by comparison of a model generated from the field´s records to current PSS®E dynamic model.
- Model parameter correction if required
- Documenting the results of the tests and analyses

. **A report with the test results and model validation per MOD 27-1 requirements is produced**.

List of Systems MOD 027



2ASE3925S| ZQ01| 4
SELECTED TURBINE SPEED
0.0÷4500.0 RPM
2ASE39250SA|
2AMKA01EE003| ZV35| 4
DROOP FOR ISLAND MODE
SET
2AMKA01EE003|
2AMKA01EE003| ZV23| 4
DROOP ACTIVE
ON
2AMKA01EE003|
2AMBA10DG005| ZV04| 4
IGV TRANSFER ON LOW FREQ
ON
2AMBA10DG005|
2AMKA01EU902A| ZQ03| 4
LOAD CAPABILITY VALUE
0.0÷250.0 MW
2AMKA01EU902A|
2AMKA01DE003A| ZQ01| 4
MW SETPOINT BEFORE DROOP
0.0÷250.0 MW
[2AMKA01DE003A|
2AMKA01DE003A|60817
HMI:0
MULTIPLY
IN1
OUT
(2x)
POLY
IN
OUT
X1
Y1
X2
Y2
X3
Y3
X4
Y4
(2x)
2AMKA01DE003A|60818
HMI:0
POLY
IN
OUT
(2x)
2AMKA01DE003A|60819
HMI:0
AXFR
NO
YES
SEL
OUT
(2x)
2AMKA01DE003A|91309
HMI:0
RAXFR
0.0 NO
OUT
YES
SEL
9999.0 RR_NO
RR_ YES
BASE
ALV
(2x)
2AMKA01DE003A|631441
IN1
IN2
(2x)
2AMKA01DE003A|92049
HMI:0
NOT
IN
OUT
(2x)
2AMKA01DE003A|92048
HMI:0
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IN
OUT
60.0 TIME
sec BASE
(2x)
2AMKA01DE003A|92046
HMI:0
AND
IN1
IN2
OUT
(2x)
2AMKA01DE003A|333600
HMI:0
MULTIPLY
IN1
0.1 IN2
OUT
(3x)
2AMKA01DE003A|61596
HMI:0
MULTIPLY
IN1
OUT
(2x)

MOD-25
Generator Real and Reactive Power Capability

SIEMENS

Purpose: To ensure that accurate information on generator gross and net Real and Reactive Power capability and synchronous condenser Reactive Power capability is available for planning models used to assess Bulk Electric System (BES) reliability.

Verification and Data Reporting of Generator Real and Reactive Power Capability

Applicable to:

>= 20 MVA (gross nameplate rating) connected to BES.

>= 20 MVA synchronous condenser (gross nameplate rating) connected to BES

>= plant/facility 75 MVA (gross nameplate rating) connected to BES . Entire plant/facility counts as one generator

Blackstart units that are part of the TOP restoration plan (PRC-019)

Variable generating units, such as wind, solar, and run of river hydro also have to be tested.

recorded

MOD-25
Verification and Data Reporting

Verification is by test or from operational data (subject to restrictions)

- A staged test for first verification will be required. The test procedures are per attachment 1 of MOD 25-2
- Operation data verification only acceptable after a staged test and with restrictions

Verification by Generator Tests

- “Verification specifications for applicable Facilities” are part of attachment 1
- Verify active and reactive capability by testing for maximum lead and lag reactive current values at maximum and minimum active power.
- A record of 1 hour long with the maximum lag reactive current for the condition of maximum active power
- For synchronous condensers, perform only the Reactive Power capability verifications
- Values of active and reactive power, terminal and field voltages **per** **MOD 25 power test data** form
- Documentation is per attachment 2 of MOD 25-2
- All auxiliary power in service, AVR in service

MOD-25
Timeline

GOs (or TOs) may elect to begin testing to meet this standard as soon as 7/1/14

Staged Enforcement Date: R1, R2 and R3 7/1/2016

Staged implementation (% of applicable unit gross MVA or percent of applicable Facilities).

- >= 40 percent by enforcement date 7/1/2016
- >= 60 percent by enforcement date 7/1/2017
- >= 80 percent by enforcement date 7/1/2018
- 100 percent by enforcement date 7/1/2019

Recurring every five years (with no more than 66 calendar months between verifications),
Same for verification using operational data

A copy of MOD 25-2 will be handed out or refer to the NERC website

MOD-26
Generator Excitation Control System or Plant Volt/Var Control Functions

Purpose:

To verify that the generator excitation control system or plant volt/var control function model (includes generator, excitation systems, voltage regulator, power system stabilizer and impedance compensator) and the model parameters used in dynamic simulations accurately represent the generator excitation control system or plant volt/var control function behavior when assessing Bulk Electric System (BES) reliability.

Applicable to:

Unit Size and Type	Generation MVA. Gross Nameplate		
	Eastern Interconnection	Western Interconnection	Ercot
Individual Units	> 100 MVA.	> 75 MVA	> 50 MVA
Generating plant. Total Generation goss aggregate nameplate	> 100 MVA	> 75 MVA	> 75 MVA

MOD-26
Verification and Data Reporting

SIEMENS

Verification is by test (R2) or from operational data

Each Generator Owner shall provide for each applicable unit, a **verified** generator excitation control system or plant volt/var control function **model**, including documentation and data, to be provided by the GO to the TP per R2.1:

Verification,

- Verification is either from a staged voltage excursion test or from a measured system disturbance

Documentation and data:

- Documentation of modelled response matching recorded response has to be provided.

Additional documentation

- manufacturer, model number, type of excitation control system and plant volt/var function
- Model structure of excitation control system, including closed loop voltage regulator or model structure for plant volt/var control function
- Compensation settings (droop, line drop, differential compensation)
- Model structure for the power system stabilizer

MOD-26
Timeline

R2 Enforcement dates: (% of the entity's applicable unit gross MVA for each Interconnection)

- 30% - 7/1/2018
- 50% - 7/1/2020
- 100% - 7/1/2024
- within 180 calendar days of a change to the excitation system or plant volt/var control function, provide revised models or plans to perform model verification
- 10 year recurring requirement

Enforcement dates R1. R3, R4, R5 and R6 - 07/01/2014

A copy of MOD 26-1 will be handed out or refer to the NERC website

MOD-26
Siemens Services

SIEMENS

Voltage Regulator On Site Testing per MOD 26-1

- Perform testing and record data
- Units off line at full speed no load
- Units on line with and without PSS in service as required
- Initial Voltage Regulator Record Review and Collection.

Data Analysis Services

- Data processing for field measurements & records
- Validating the actual PSS®E dynamic models
- Documenting the results of the tests and analyses

Generator Tests are to validate the generator model, and excitation system performance.

- generator model - verification of the d-axis synchronous reactance, saturation points and leakage reactance.
- measuring the static characteristic of the AVR (field voltage vs. terminal voltage) for different dispatch conditions.
- active and reactive power, terminal and field voltages are recorded.

MOD-26
Siemens Services

SIEMENS

Generator Excitation Control Systems Models Verification

- dynamics of the response both at open circuit and interconnected to the BES
- The step at the voltage reference of the AVR will be applied by Siemens.

Power System Stabilizer (PSS) Models Verification

- The model validation of the PSS will be achieved by simulation of a step response (local mode test) with the PSS switched to on.
- Siemens will validate the PSS dynamic response by comparison of a model generated from the field´s records to current PSS®E dynamic model.

A report with the test results and model validation is produced.

List of systems MOD 26

MOD-032-1
Data for Power System Modeling and Analysis

SIEMENS

Purpose

- To establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system.

Services

- Collection and provision of GO and LSE relevant steady state, dynamics and short circuit data. See attachment1 of MOD-032

Time-Line

- Supply of steady-state, dynamics, and short circuit modeling data for Power System Modeling and Analysis.

07/01/2015 R1 - PC, TP
07/01/2016 R2 - BA, GO, LSE, RP, TO, and TS. R3 - PC, TP, R4 - PC

PRC-019
Plant Protection

Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection.

Purpose:

- Verification coordination of generating unit Facility or synchronous condenser voltage regulating controls, limit functions, equipment capabilities and Protection System settings.

Services

- Calculation of required and adjustment of voltage regulator limits and protection limits as well as test of protection coordination.

Time-Line

- Verification of coordination of plant capabilities, voltage regulating controls and protection system settings. Enforcement date 07/01/2016. Phased enforcement

PRC-024
Generator Frequency and Voltage Protective Relay Settings

SIEMENS

Purpose:

- Ensure Generator Owners set their generator protective relays such that generating units remain connected during defined frequency and voltage excursions.

Services

- Review and verification of Generator Frequency and Voltage Protective Relay Settings for correct coordination per the grid requirements. Adjust as required.

Time-Line

Verification of generator frequency and voltage protective relays settings – relay/ AVR limiter coordination. Enforcement date 07/01/2016. Phased enforcement

NERC Testing
Siemens Services – Which Products

MOD 27

- **All Siemens controls systems**
- **All Westinghouse controls systems**
- **All Siemens turbines including Allis Chalmers, Westinghouse, Parsons**
- **Third party controls systems**

MOD 25

- **All Siemens generators**
- **All Westinghouse generators**

MOD 26

- **All Siemens excitation systems.**
- **All Westinghouse excitation systems.**
- **Third party excitation systems.**.

MOD 32

- **Same as MOD 025, 026 and 027**

PRC-019

- **Plant related**

PRC-024

- **Plant related**.

NERC Testing
Siemens Services – Who to contact?

- **Your Sales Representative or Sales Account Manager**
- **The District Services Manager**
- **The Service Manager or Service Project Lead**
- **+1 770-740-3000, ask for the service manager**

Q&A

7

Daniel Lee, Sr. Consulting Engineer

ABB process to alert or educate the generator owner/ operators

1) Primary Frequency Control – Solution for NERC BAL-001-TRE (ABB's pre-approved proposal) (2015 -2018)
2) Generator Governor Frequency Control (Application Guide) (2015)
3) Strategies that address the challenges of balancing load and unstable grid frequency (technical paper) – Presented at; ABB Customer World (3/15/2017) and 2017 ISA POWID Symposium (6/17/2017)
4) Meeting NERC's BAL-003 Generator Governor Frequency Response (technical paper) – Presented at 2015 ISA POWID Symposium (6/8/2015)


US POWER AND WATER CUSTOMER

Primary Frequency Control

Solution for NERC BAL-001-TRE

Issue Date: 1/31/2018

Reference Number: PG-PFC-2018 Rev 00

Power Generation

Application Guide: Utility, Simple Cycle, and Combined Cycle Generator Governor Frequency Control

Contact Information:

Daniel Lee (dan.lee@us.abb.com)

Vern Smith (vernon.smith@us.abb.com)

NERC emphasis of Primary Frequency Withdraw

1) October 30, 2012, NERC published Frequency Response Initiative Report: The Reliability Role of Frequency Response.

    Frequency Response Withdraw is discussed multiple times on multiple pages.

2) Feb 5, 2015, NERC issues an industry advisory specifying the method to improve grid stability by;

    Frequency Response Withdraw is discussed in one sentence "Related outer-loop controls within the DCS, as well as other applicable generating unit or plant controls, should be set to avoid early withdrawal of primary frequency response."

3) Dec 15 2015, NERC Operating Committee approved the "Reliability Guideline: Primary Frequency Control"

    Frequency Response Withdraw is only mention in the performance assessment. Guidelines do not identify withdraw problem or requirements a solution to resolve frequency response withdraw.

NERC Survey Assessment

1) The survey assesses both the secondary frequency control and primary frequency control response.

   Consider adding Unit Master Setpoint (demand) to data collection. Unit Master setpoint should be subtracted from the megawatt response in order to evaluate the primary frequency control. OK to also assess the response of secondary frequency control

2) NERC needs to verify the calculation can correctly compute the front end withdraw behavior.

   In my opinion, the current calculation do not.

NERC PFC Guidelines vs Mod 27

1) The Reliability Guidelines for Primary Frequency Control and MOD 27 are related but separate NERC requirements.
2) NERC intends that the Generator Owners/Operators implement both of these documents.
3) The data collected from the MOD 27 test can be used to calibrate the boiler frequency correction bias required by the Reliability Guidelines for PFC.

ABB

Emerson Process Management
Power & Water Solutions

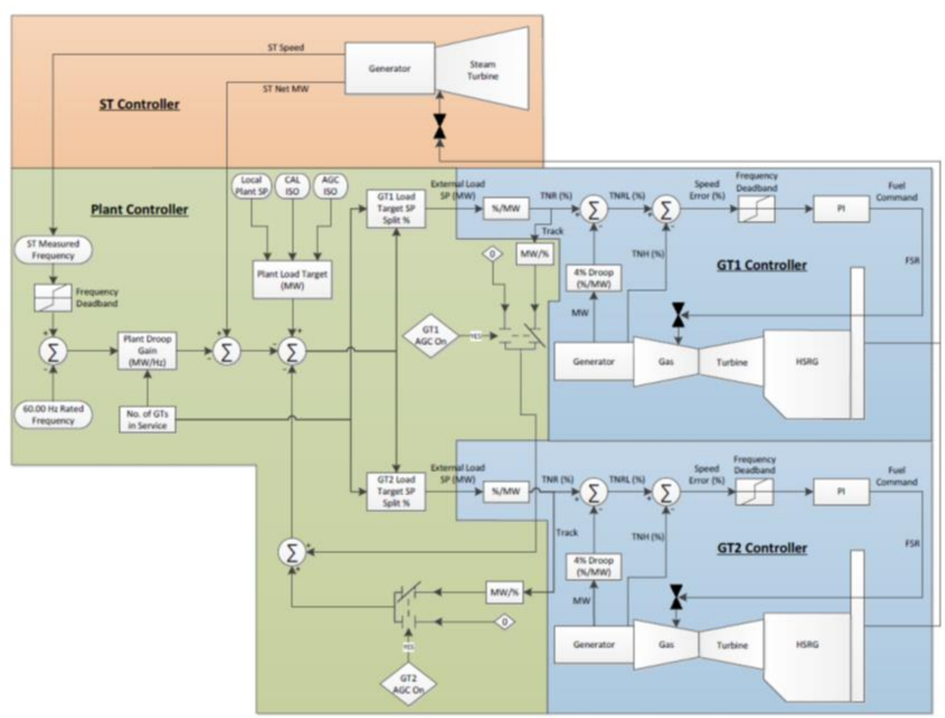
Combined Cycle Frequency Response

Thor Honda
Steam Turbine Business Development Manager
(412) 963-4272
thor.honda@emerson.com

EMERSON

Coordinating Power Plant Control Systems and Automatic Generation Control (AGC)

- Coordinating configuration of governor and plant load control systems is the key to providing a sustained (non-squelched) frequency event response
- Most turbine controls have frequency (droop) control but may need settings adjusted or enabled
- Combined Cycle plants with closed-loop load controls will need frequency logic to prevent squelching
- Emerson is often NOT the designer of Combined Cycle load controls (AE firms are most common)

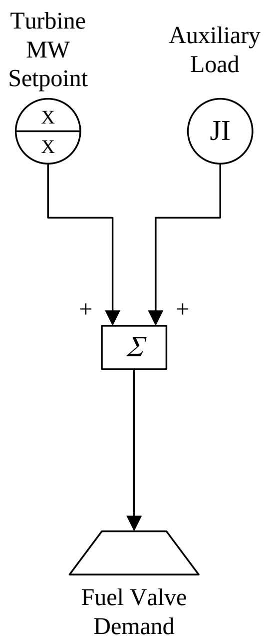


EMERSON

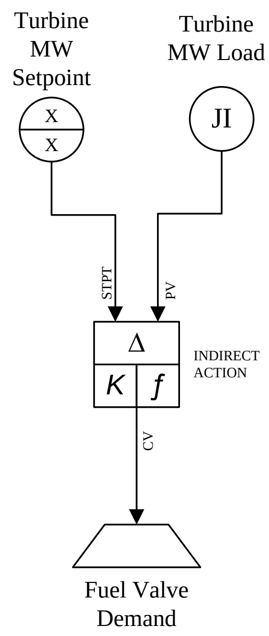
Combined Cycle Automatic Generation Control (AGC)

- Site or Power Block level AGC generally comes in two flavors:

<u>Open Loop Control</u>



<u>Closed Loop Control</u>



AGC Bias Requirement

Point A

Pre-disturbance Frequency

Point C

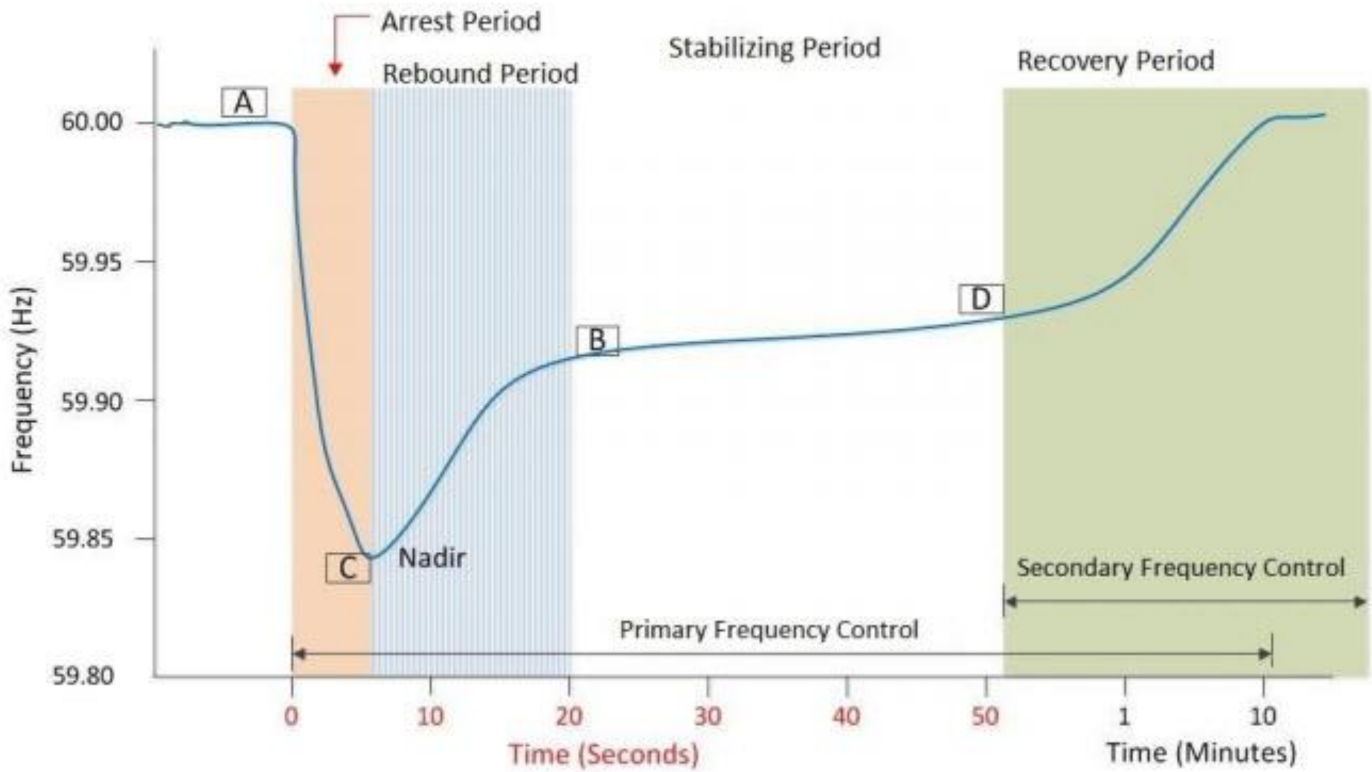
Nadir – or maximum deviation due to loss of resource

Point B

Stabilizing frequency

Point D

Time the contingent Balancing Authority begins to recover from the loss of resource



AGC Bias Requirement

Time A

Grid frequency drops, initiating a droop response to the turbine controller

Time B

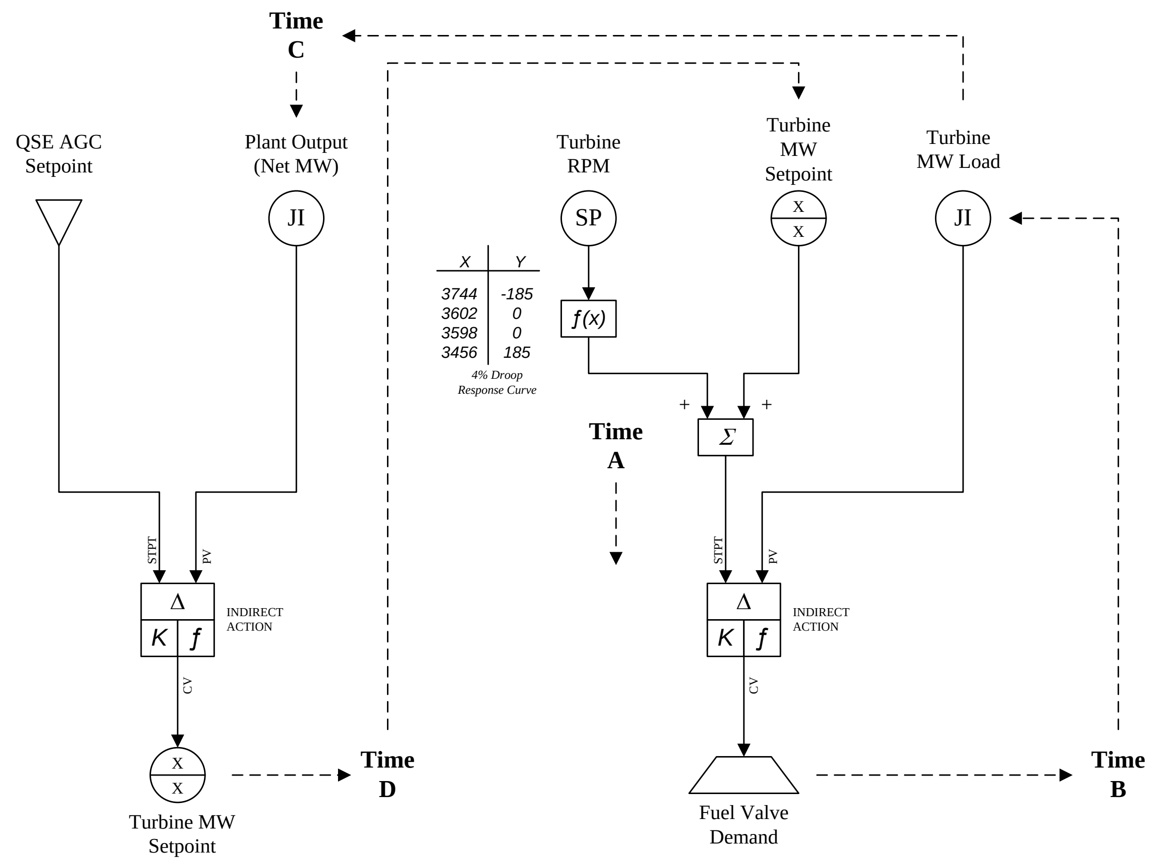
Turbine load increased due to droop response, at turbine ramp rate

Time C

Plant output increases due to turbine load increase

Time D

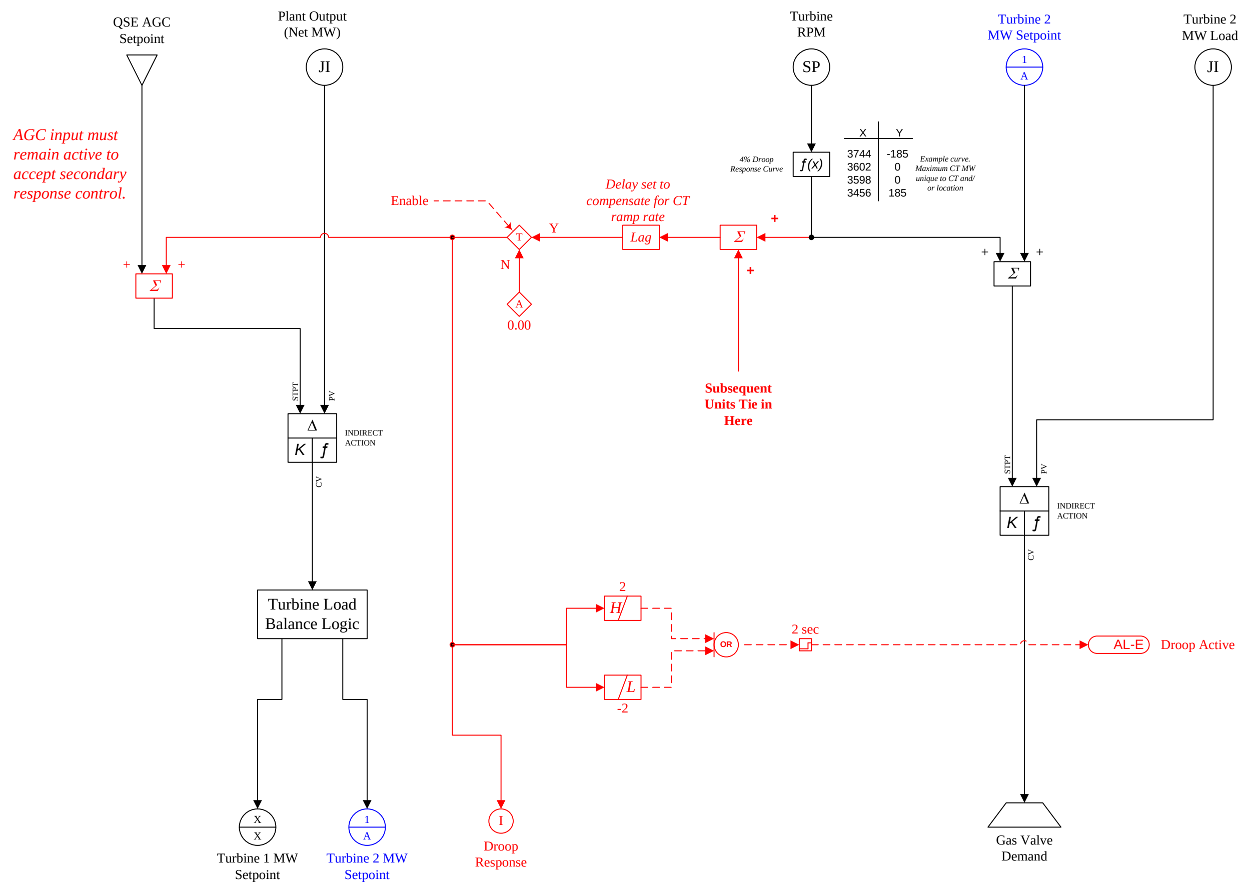
AGC control lowers turbine load setpoint due to plant load increase



AGC Bias Implementation

Droop Response Available:

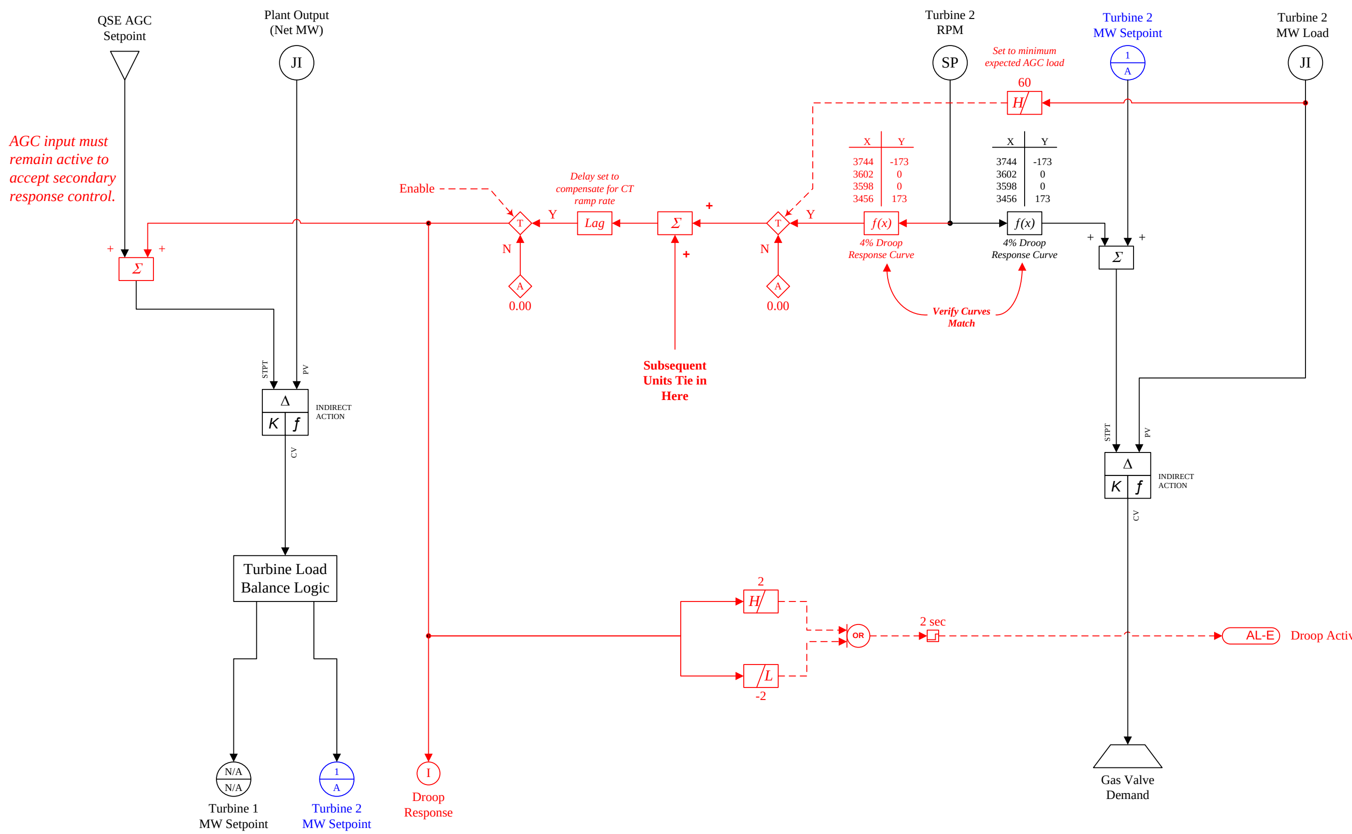
- Generally only available on systems that utilize the same control system for turbine governor control as well as balance of plant (BOP) control, where AGC resides.
- Freezing AGC response would preclude Secondary Frequency Response by the Balancing Authority (BA).



AGC Bias Implementation

Droop Response - Replicate:

- Most prevalent.
- Accuracy of speed signals paramount.
- Regeneration of droop response on active turbine(s) only.



Summary

- Verify unit specific requirements with your Balancing Authority (BA)
- If operating closed loop AGC control, biasing may be required to pass BA compliance criteria.
- When implementing AGC Bias:
  - AGC will not negate droop impact on site output, which may have economic considerations.
  - Ensure AGC Bias is accurate and enabled accordingly.

EMERSON™

FPL Frequency Response Improvements

FPL I&C Fleet Team

Background

- Poor frequency response is the result of using megawatt generation control without frequency error bias.
- The following cases illustrate improvements FPL made to plant load control logic to improve frequency response.

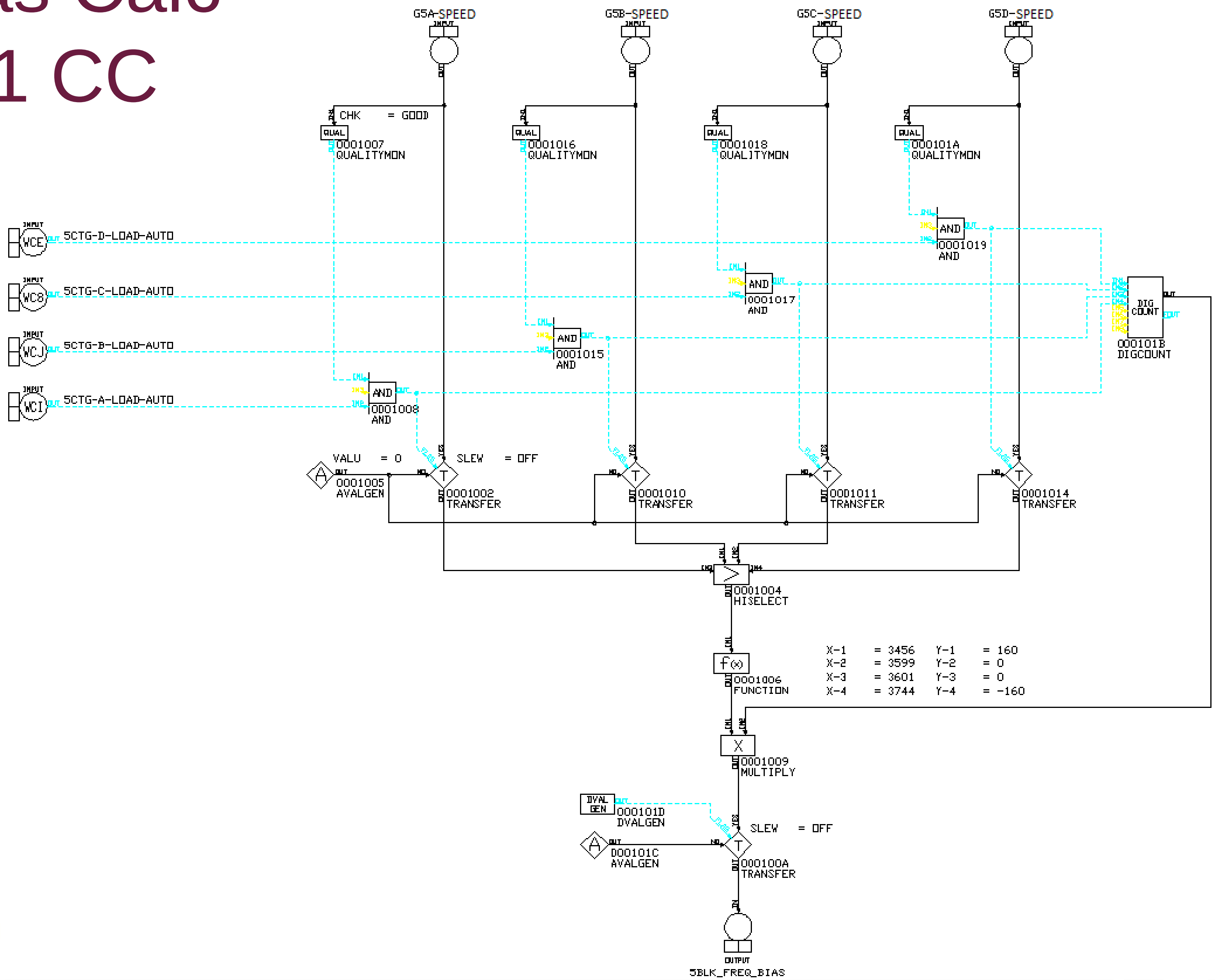
FPL

Cases

Case	Plant control	Turbine control	Change
1	Feed forward with feedback trim and no freq err bias	Load control w/no freq err bias	Added freq bias to plant control feed forward and feedback controller setpoint
2	Feed forward with feedback trim and no freq err bias	Load control w/freq err bias	Added freq bias to plant control feedback controller setpoint
3	Feedback with no freq err bias	Speed control w/freq err bias	Added freq bias to plant control feedback controller setpoint

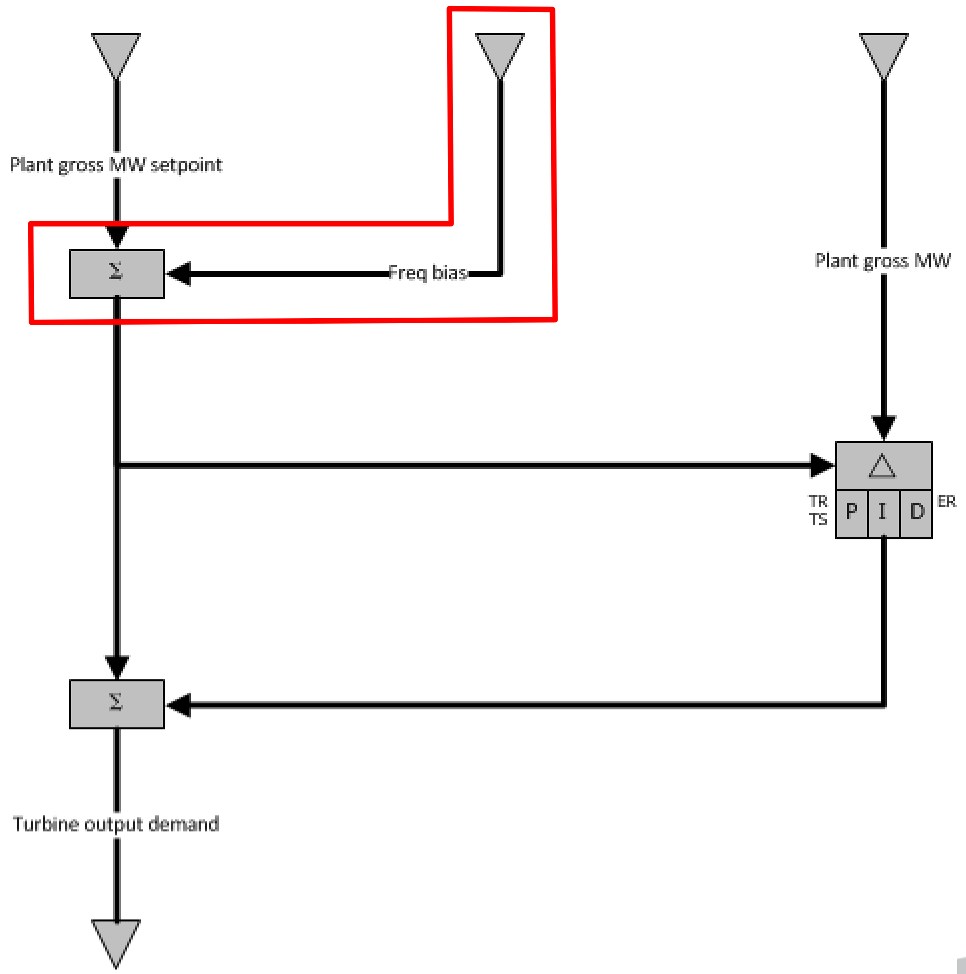
FPL

Bias Calc
401 CC



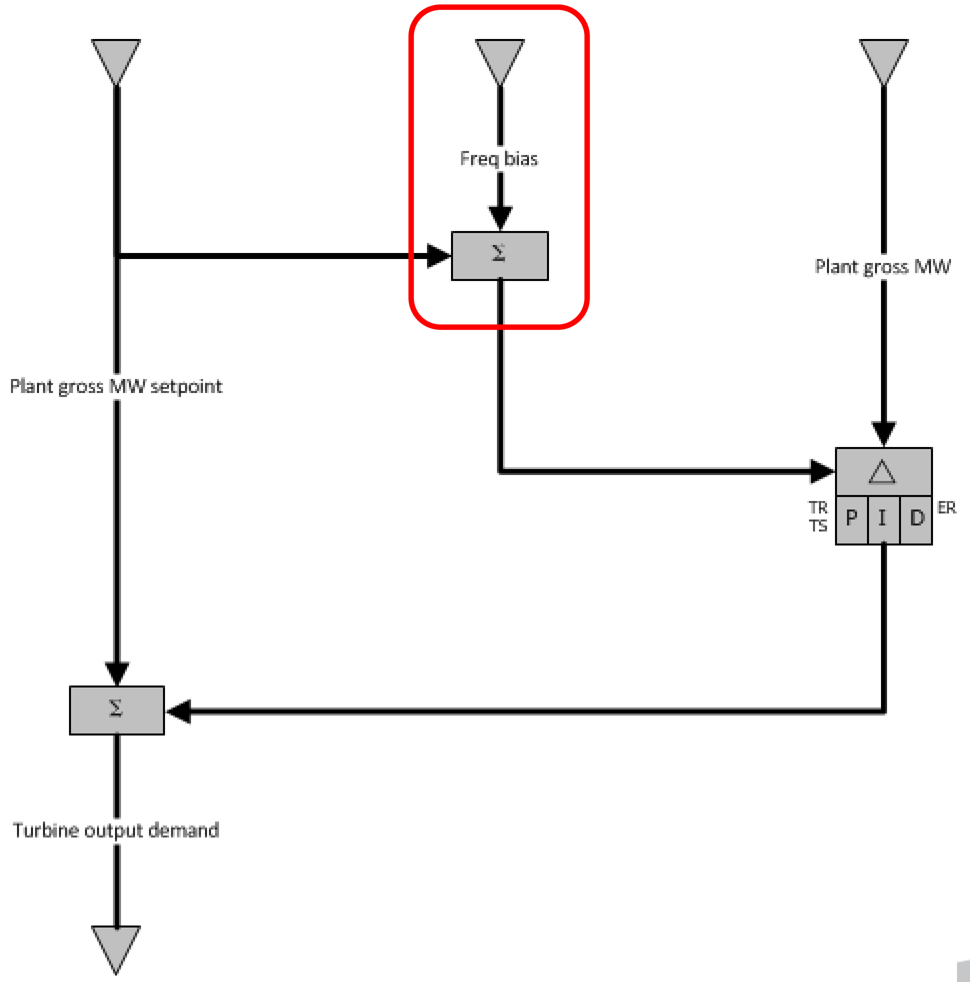
FPL

Case 1

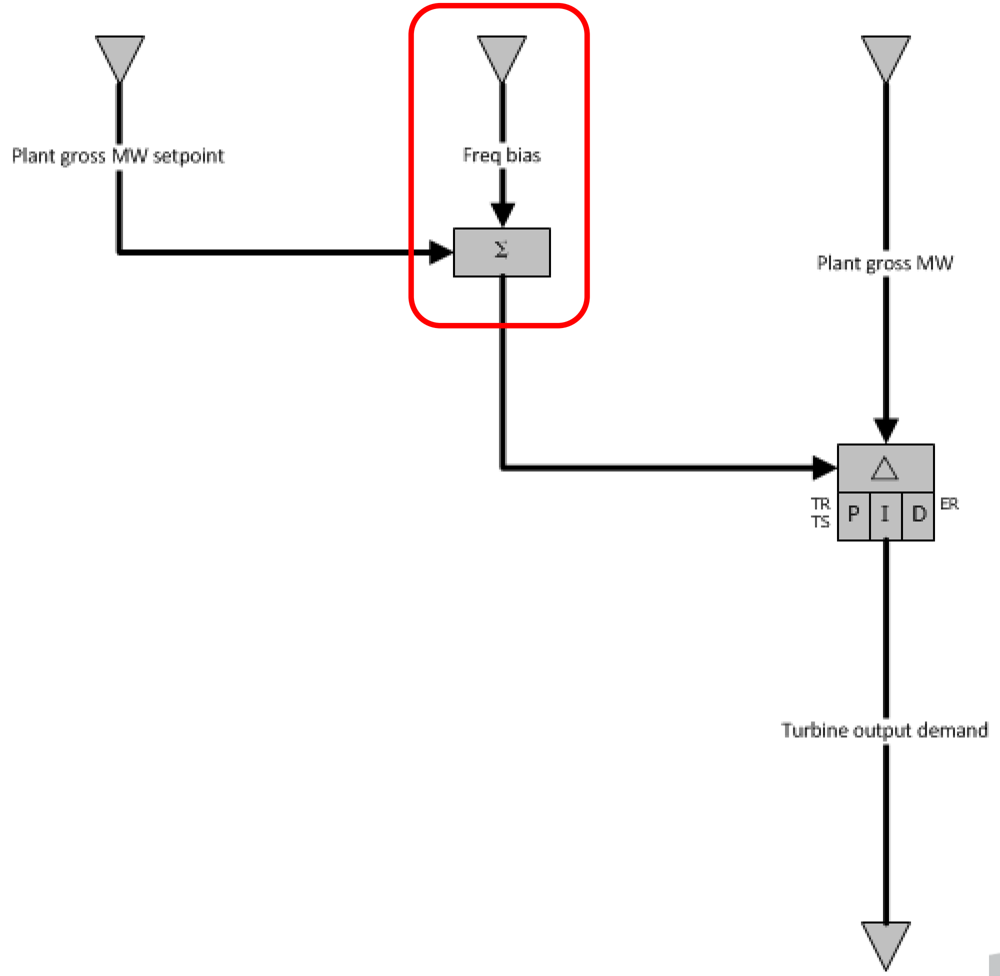


Plant gross MW setpoint
Σ
Freq bias
Plant gross MW
TR
TS
P
I
D
ER
Σ
Turbine output demand

Case 2


Freq bias
Σ
Plant gross MW
Plant gross MW setpoint
TR
TS
P
I
D
ER
Σ
Turbine output demand

Case 3



Plant gross MW setpoint
Freq bias
Σ
Plant gross MW
TR
TS
P
I
D
ER
Turbine output demand

Southern Company

NAGF Subcommittee – Natural Gas Combine Cycle/ Simple Cycle
PFR Outer Loop Controls

Frank Buttler / November 13, 2018

Operations

Biography

- Frank C Buttler Jr, P.E.
  - Consulting Engineer
  - Johnson Services Group
  - Southern Company Generation
  - Engineering and Construction Services, Technical Services, ERO Support
  - Email: x2fcbutt@Southernco.com or fbuttler@bellsouth.net
  - Phone 770-401-3944
- BSEE Auburn University, 1978
- Retired from Southern Company after 40 years of service in Power Plant Electrical and I&C Field Support.
- Started consulting to Southern Company Generation in 2014 for MOD-027-1 Turbine Frequency Response Testing.
- Over the last four years, performed frequency step testing, modeling simulations, and frequency response recommendations on 10 Hydro Units, 15 Fossil Steam Units, and 23 Combustion Turbines for MOD-027-1.
- Performed testing and frequency response recommendations on 9 Fossil Steam Units and 19 Combine Cycle Units for Outer Loop Controls.

Agenda

- Outer Loop Control Philosophy
- Internal Outer Loop Controls – GE Combustion Turbine
  - GE Mark V
  - GE Mark VI
  - GE Mark VIe
- External Outer Loop Controls
  - CT
  - Combine Cycle
- Conclusions/Recommendations
- Other Considerations
- Questions

Outer Loop Control Philosophy

- Droop control response should be controlled at the lowest level
  - As close to the governor controls as possible

- Turbine Controls provides the Droop Response capabilities

- Outer Loop Controls should not affect the Turbine Controls Frequency Megawatt Response

- Outer Loop Controls if Not Accounted for will NULL out the Frequency Megawatt Response during a Frequency Event
  - Outer Loop Megawatt Controller “Sees’ the Unit Megawatts are off Setpoint Target and Moves the Megawatt Setpoint to Correct the Error

Internal Outer Loop Controls – GE Combustion Turbine

- General Electric 7FA Combustion Turbine
- Mark V Turbine Control System
- 175 MW Output
- Megawatt Setpoint set in Preselect Mode
- 4% Droop
- 0.025% or 0.015 Hz Deadband
- 0.2% or 0.120 Hz or 7.2 RPM Speed Step Change
- Expected Megawatt Response to the Speed Step Change
  - $7.7\ \mathrm{MW} = 175\ \mathrm{MW}\left[\frac{(0.120\ \mathrm{Hz\ step} - 0.015\ \mathrm{Hz\ deadband})}{(0.04\ \mathrm{droop})(60\ \mathrm{Hz})}\right]$
  - Speed Step was applied on System Frequency so Megawatt Output will vary Dependent on System Frequency +- Speed Step

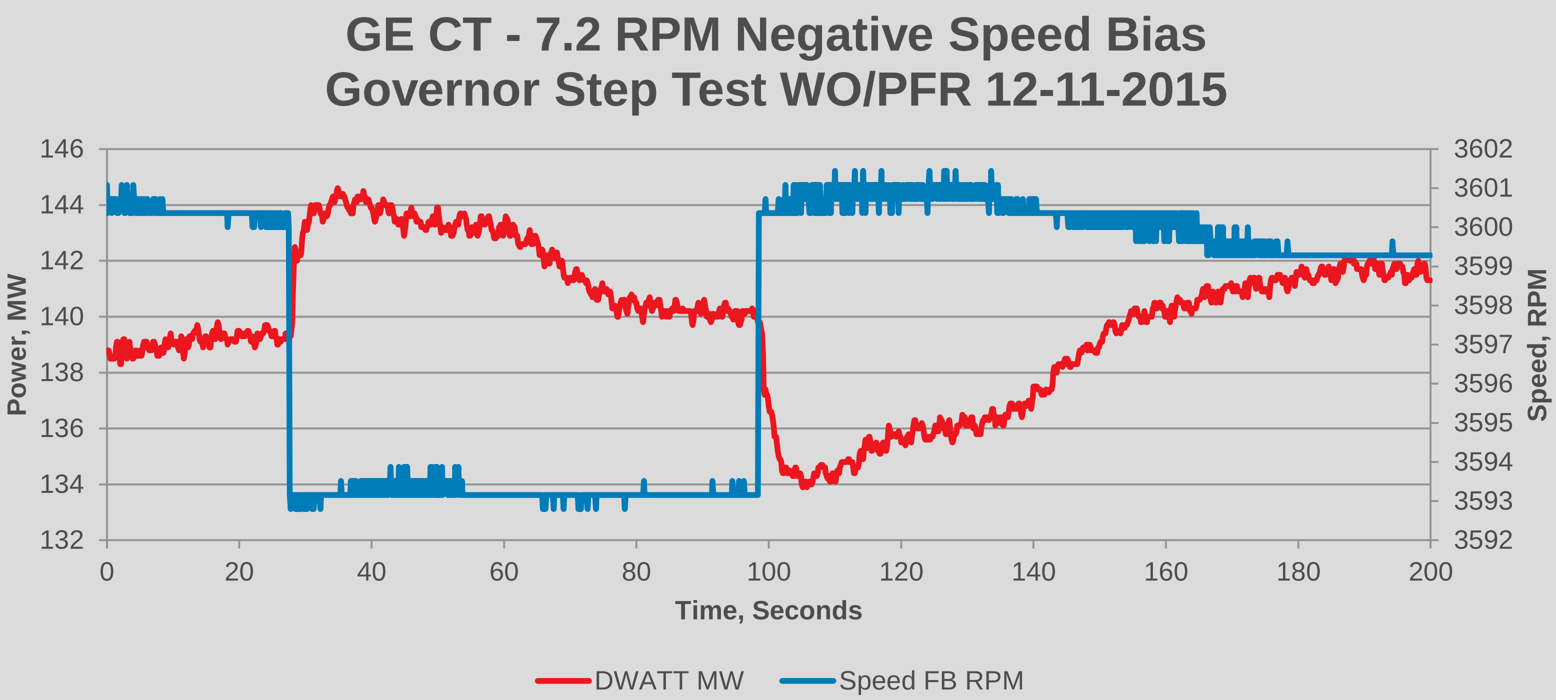
Internal Outer Loop Controls – GE Combustion Turbine

- Initial Testing found that the Internal Megawatt Outer Loop Control Nulled out the Megawatt Response to the 7.2 RPM Step
- Corrected the Problem by Adding Primary Frequency Response (PFR) Logic to the Mark V Turbine Controls
- Mark VI and Mark VIe Turbine Controls will Exhibit the Same Droop Response Characteristics Without PFR Logic Added
- GE Mark VIe PFR Application
  - Primary Frequency Response (PFR) is part of the OpFlex Enhanced Transient Stability (ETS) package offered by General Electric for Mark VIe governor controls. This package for the Mark VIe sustains the droop response to a frequency event as desired per NERC frequency initiative guidelines.

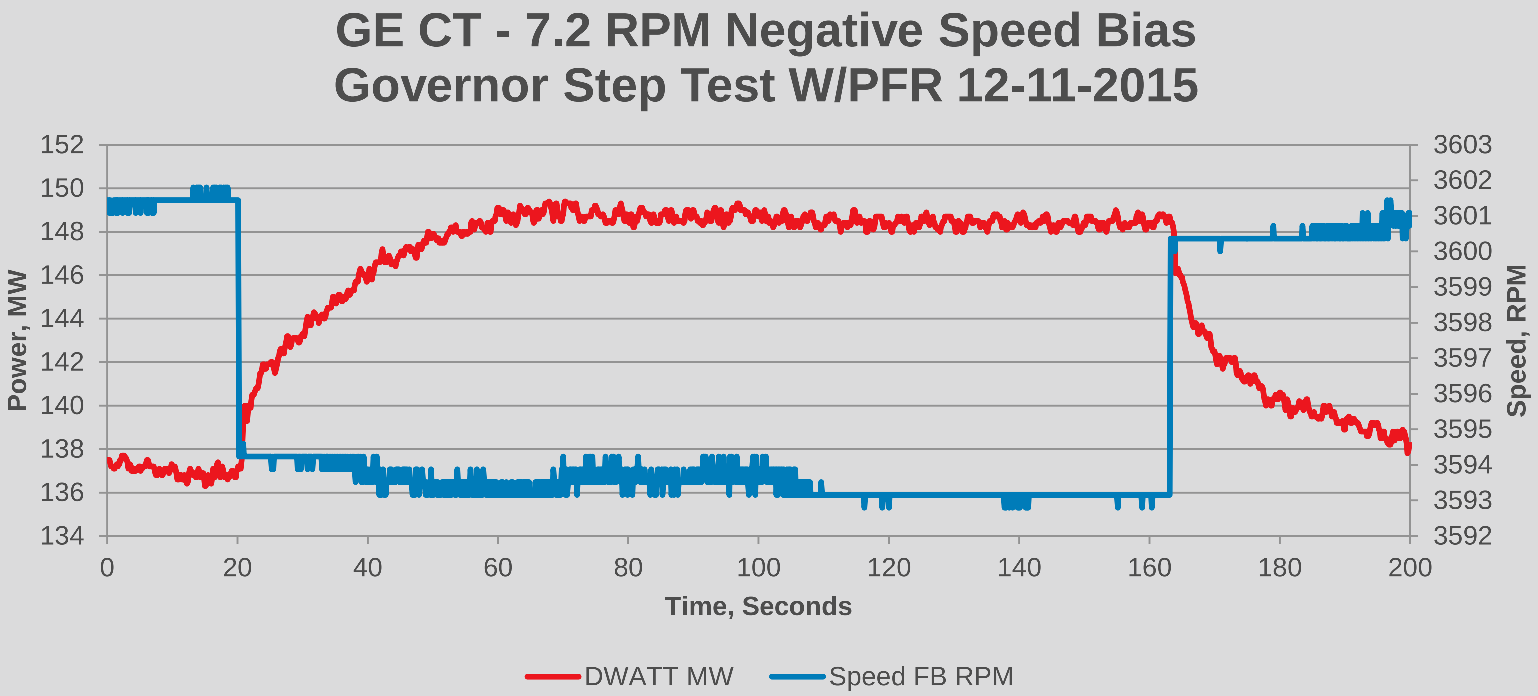
- Note: PFR Not Needed for MOD-027-1 Compliance but does not meet the Intent of NERC Frequency Response Initiative

- Note: Not an Issue with Siemens T3000. Mitsubishi Netmation had to be Modified to Perform a Sustained Droop Megawatt Response

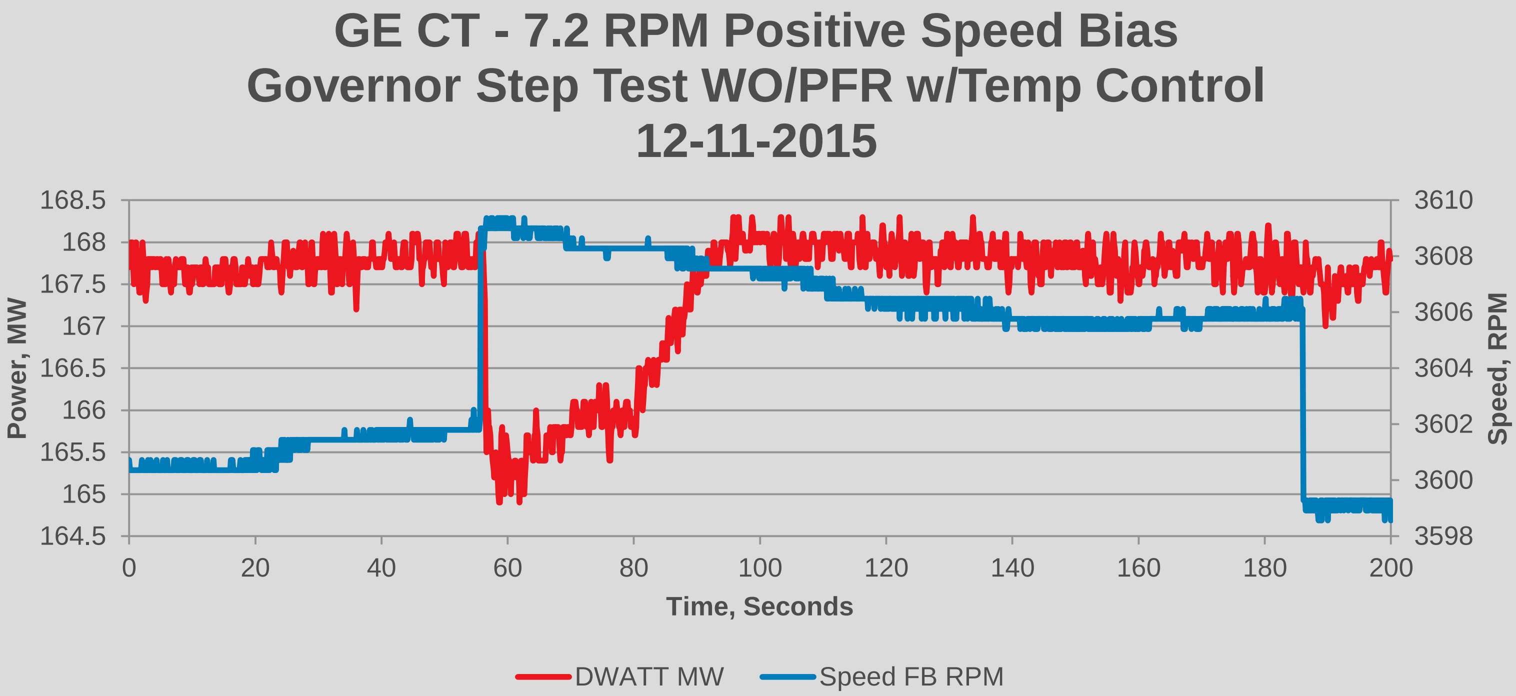
Internal Outer Loop Controls – GE Combustion Turbine



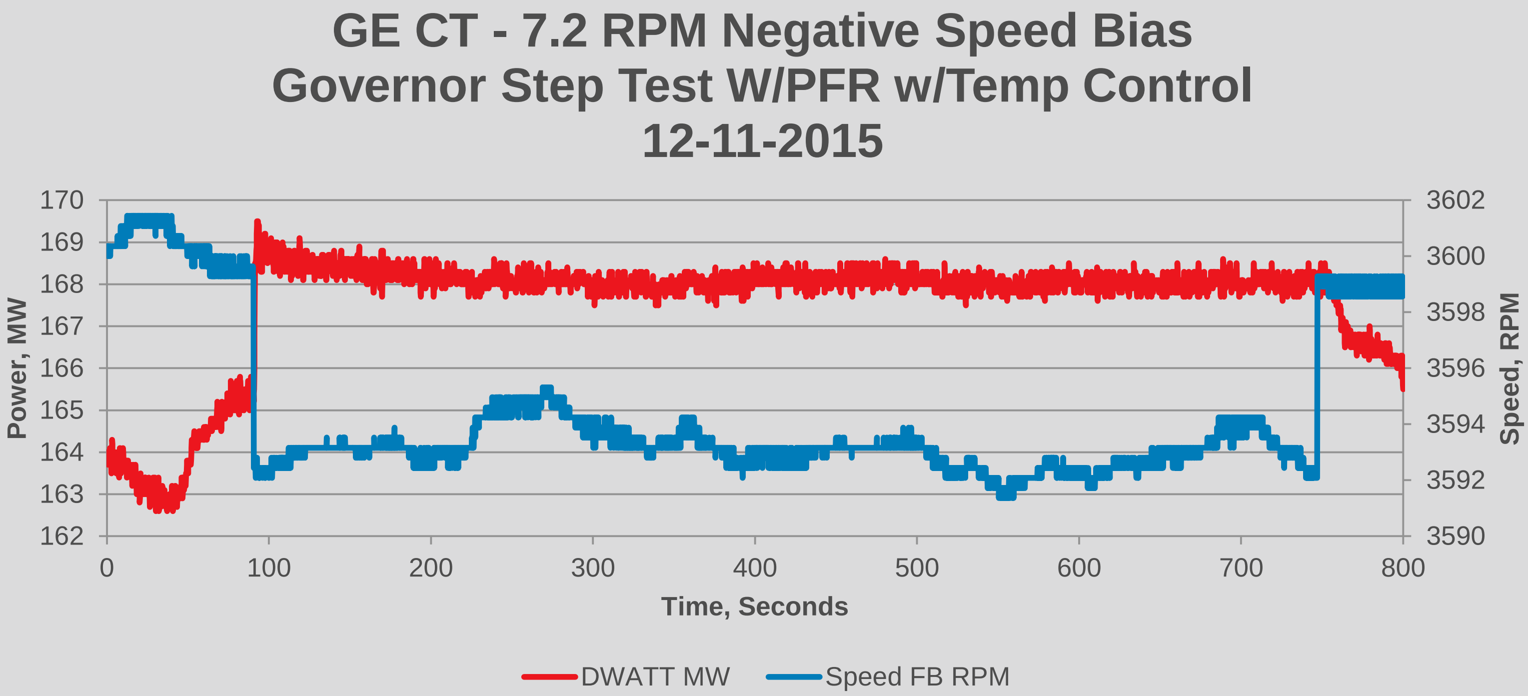
Internal Outer Loop Controls – GE Combustion Turbine



Internal Outer Loop Controls – GE Combustion Turbine



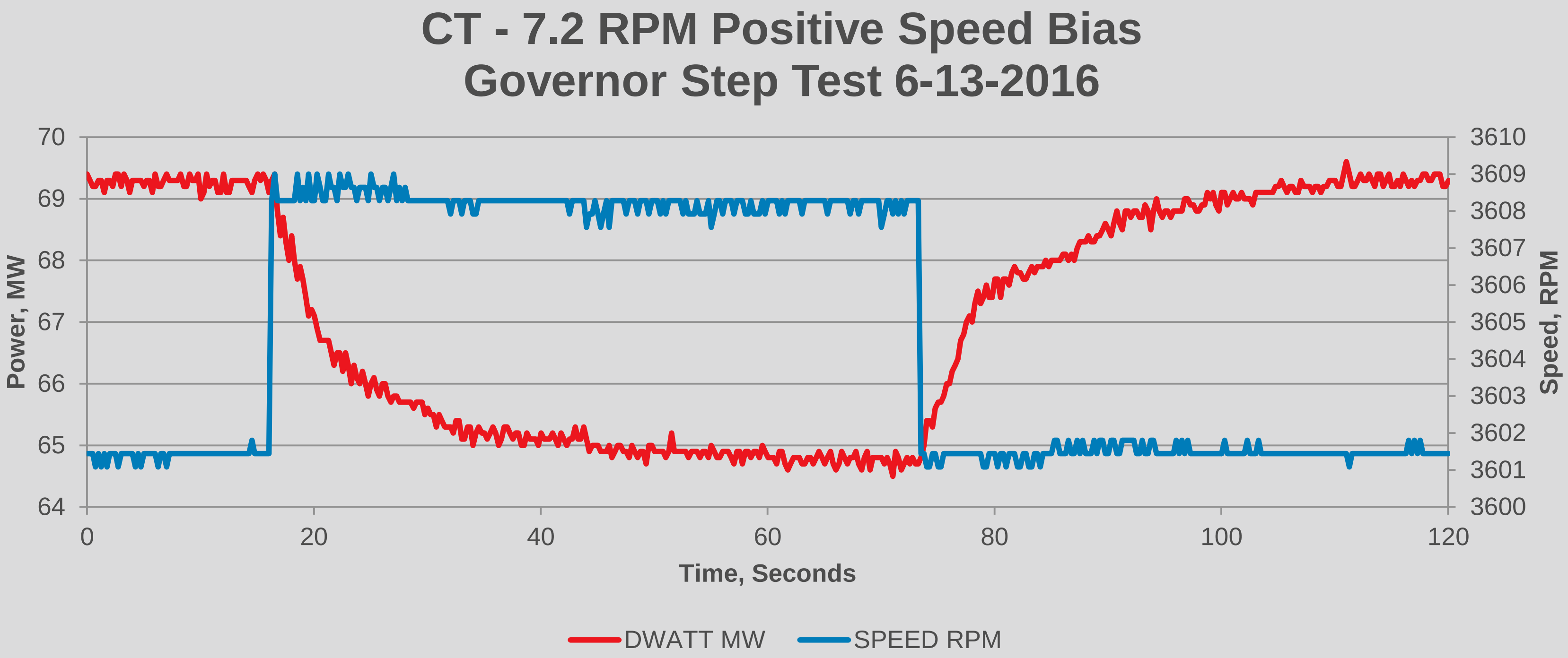
Internal Outer Loop Controls – GE Combustion Turbine



External Outer Loop Controls – Combustion Turbines

- CT's
  - CT Units in Southern Company do not have Outer Loop Controls
  - Some Have PLC Based Control But Only Supply System (AGC) or Operator Setpoint Commands
- General Electric 7EA Combustion Turbine
- Mark V Turbine Control System with PFR
- 75.6 MW Output
- Megawatt Setpoint set in Preselect Mode
- 4% Droop
- 0.025% or 0.015 Hz Deadband
- 0.2% or 0.120 Hz or 7.2 RPM Speed Step Change
- Expected Megawatt Response to the Speed Step Change
  - $3.3\ \mathrm{MW} = 75.6\ \mathrm{MW}\left[\frac{(0.120\ \mathrm{Hz\ step} - 0.015\ \mathrm{Hz\ deadband})}{(0.04\ \mathrm{droop})(60\ \mathrm{Hz})}\right]$
  - Speed Step was applied on System Frequency so Megawatt Output will vary Dependent on System Frequency +- Speed Step

External Outer Loop Controls – Combustion Turbines



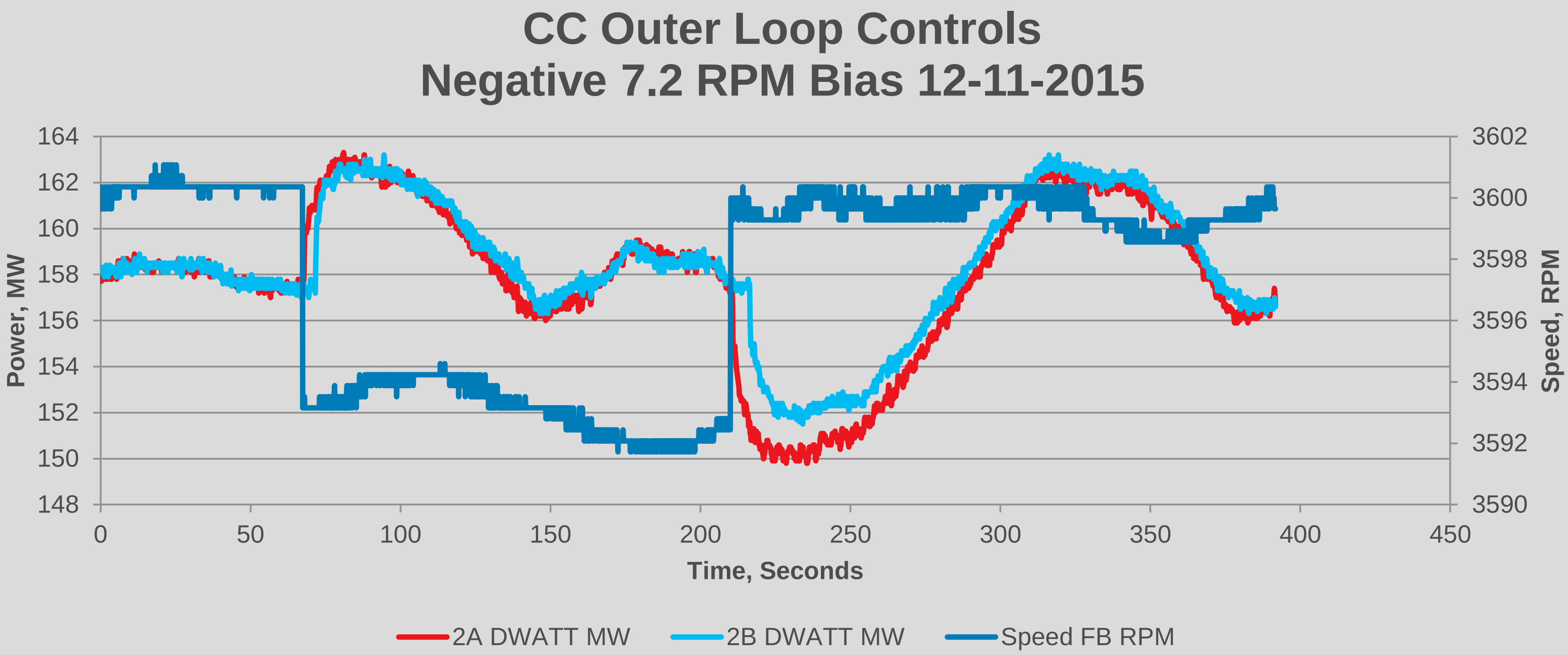
External Outer Loop Controls – Combine Cycle

- Two General Electric 7FA Combustion Turbines
- Alstom Steam Turbine
- Mark VIe Turbine Control Systems with PFR for CT's
- Alstom Turbine Control System for Steam Turbine
  - The Steam Turbine is not Frequency Responsive but will Slowly Change the Megawatt Output Based on the CT Exhaust Output
- 182.5 MW Output per CT
- Total MW Output of 600 MW
- Megawatt CT Setpoints set by Emerson Ovation to Achieve Unit Output Setpoint
- 4% CT Droop
- 0.02% or 0.012 Hz CT Deadband
- 0.2% or 0.120 Hz or 7.2 RPM Speed Step Change

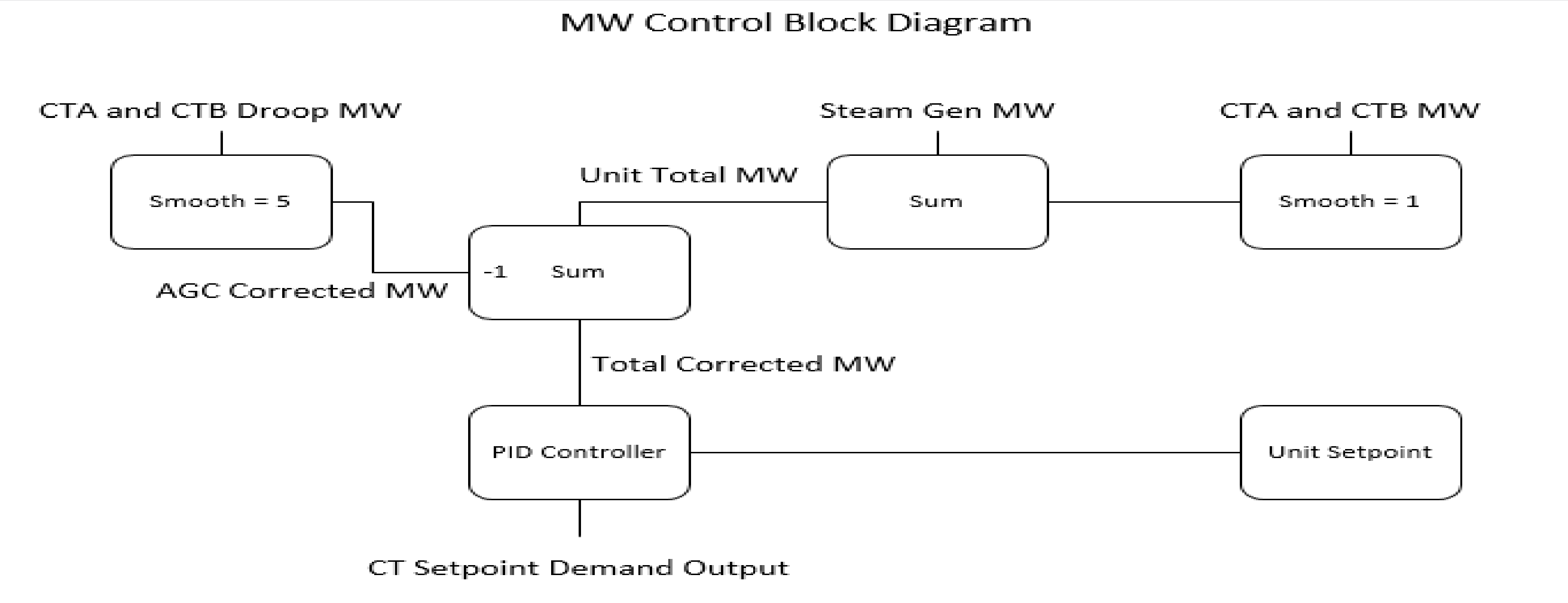
External Outer Loop Controls – Combine Cycle

- CT's Provide the Outer Loop Controls the Droop Response Bias Megawatts
- Expected Megawatt Response to the Speed Step Change
  - $16.4\ \text{MW} = 2 * 182.5\ \text{MW}\left[\frac{(0.120\ \text{Hz step} - 0.012\ \text{Hz deadband})}{(0.04\ \text{droop})(60\ \text{Hz})}\right]$
  - Speed Step was applied on System Frequency so Megawatt Output will vary Dependent on System Frequency +- Speed Step
- CT Megawatt Setpoints Should not Change During the Frequency Step
  - Constant Megawatt Setpoint During Steady State
    - Due to Data Input Timing, May have a Deviation in the CT Megawatt Setpoint at the Step Injection Points. Tune to Keep this CT Setpoint Megawatt Deviation to a Minimum
  - Constant Slope Megawatt Setpoint During a Ramp

External Outer Loop Control – Combine Cycle
Not Accounting for Frequency Deviation Outside Droop Deadband



External Outer Loop Controls – Combine Cycle

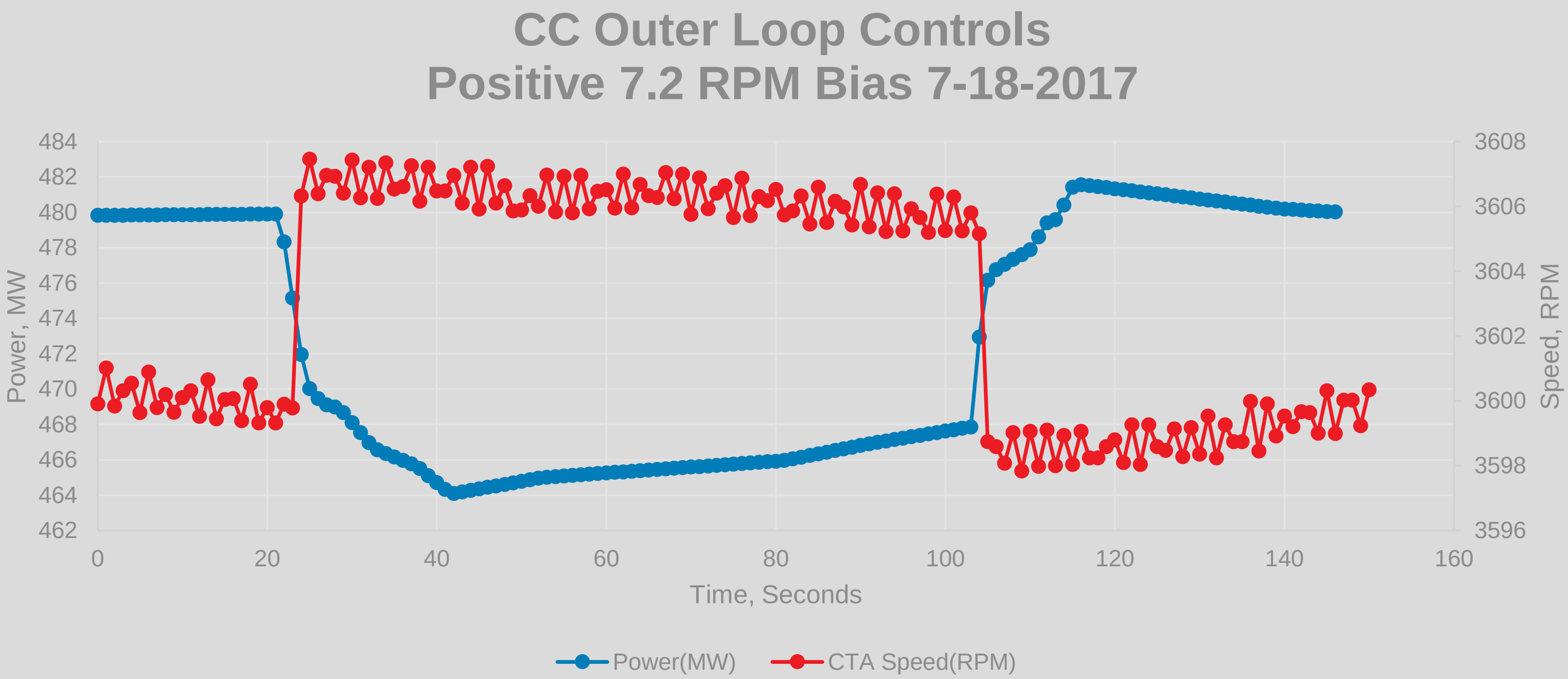


External Outer Loop Controls – Combine Cycle

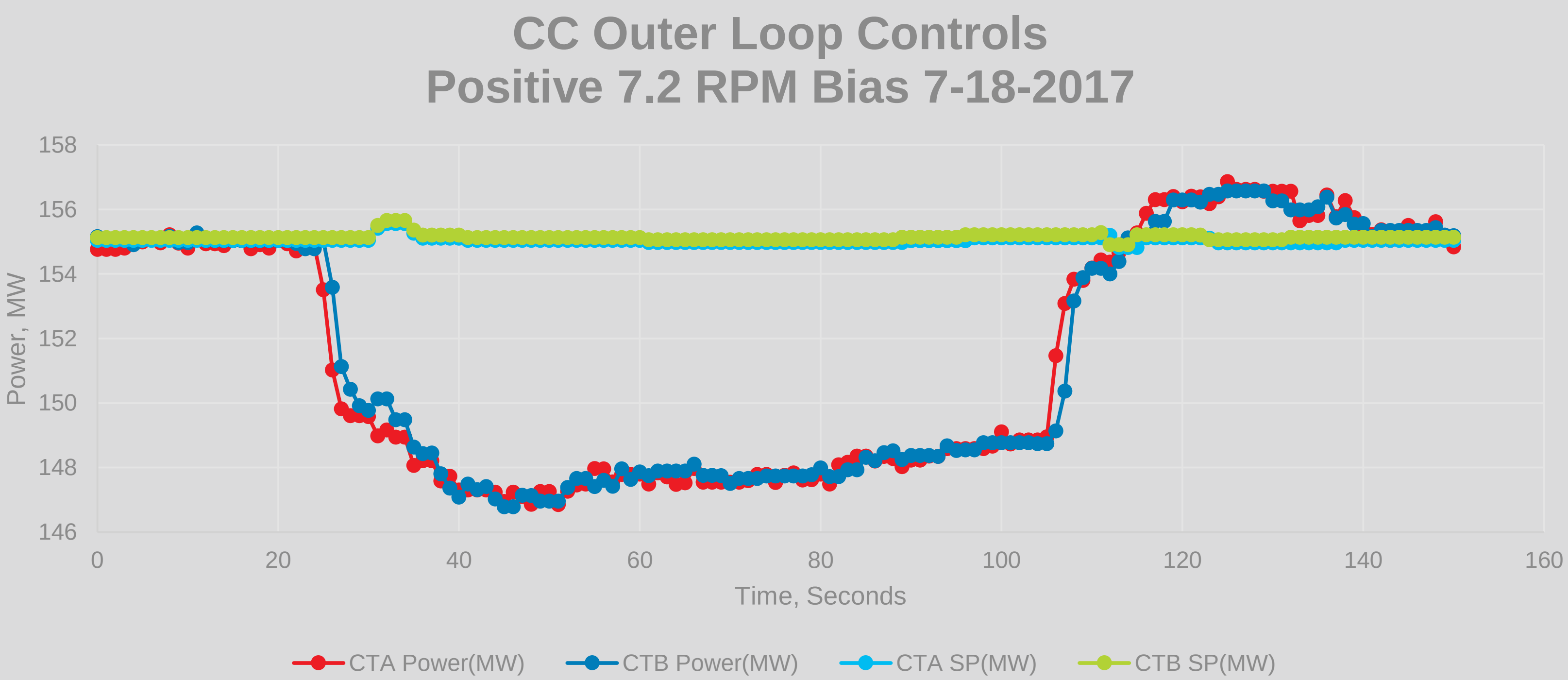
- During normal unit operation with the frequency within the droop deadband:
  - Assume the Unit Setpoint is 500 MW, Unit Total MW is 500 MW and AGC Corrected MW is 0 MW. The AGC Corrected MW (0 MW) is subtracted from the Unit Total MW (500 MW) results in the Total Corrected MW being 500 MW. The inputs to the PID controller will be Total Corrected MW of 500 and setpoint of 500. This results in no change of the CT setpoint demand output.

- During normal unit operation with the frequency outside the droop deadband and each CT supplying 10 MW of droop as response to the frequency deviation over the droop deadband:
  - Assume the Unit Setpoint is 500 MW, Unit Total MW is 520 MW (increased by 20 MW due to the droop response of the CT's) and AGC Corrected MW is 20 MW. The AGC Corrected MW (20 MW) is subtracted from the Unit Total MW (520 MW) results in the Total Corrected MW being 500 MW. The inputs to the PID controller will be Total Corrected MW of 500 and setpoint of 500. This results in no change of the CT setpoint demand output and thus does not affect the droop response of the CT's.

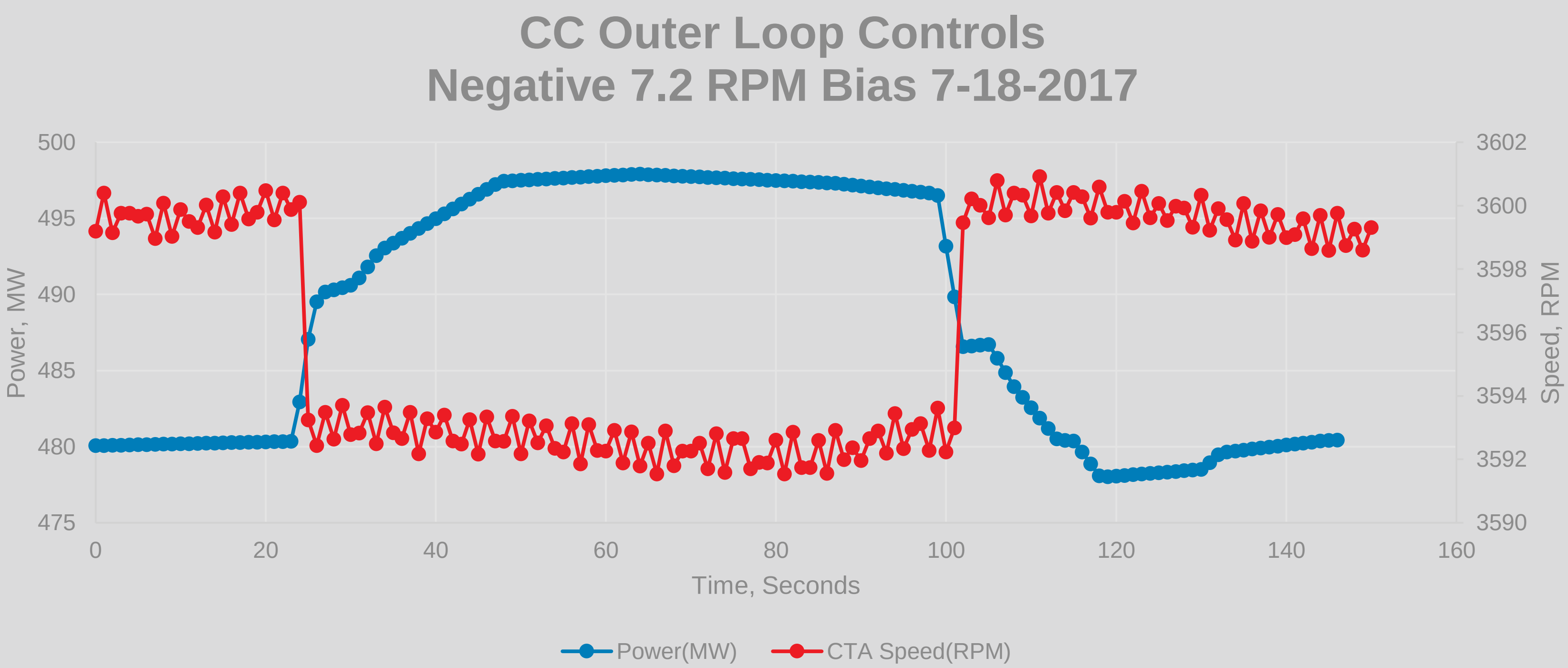
External Outer Loop Controls – Combine Cycle



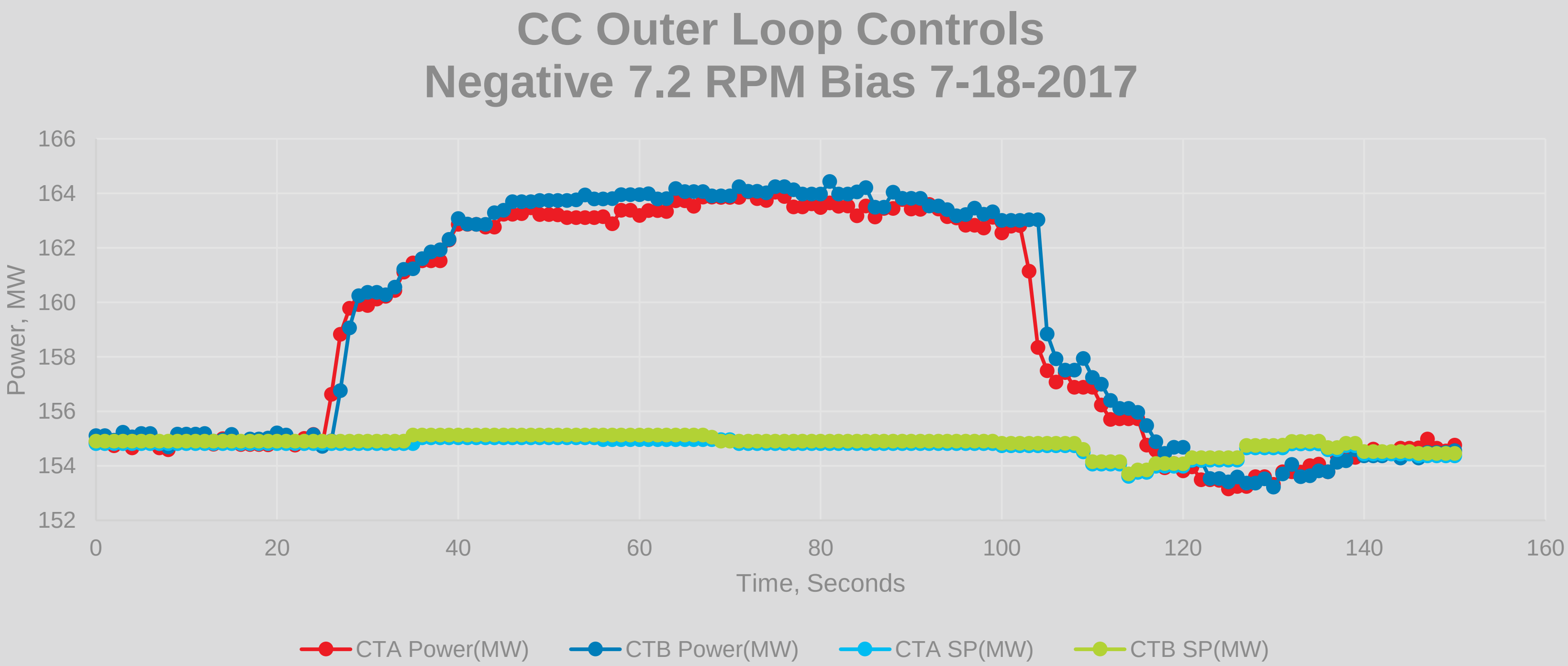
External Outer Loop Controls – Combine Cycle



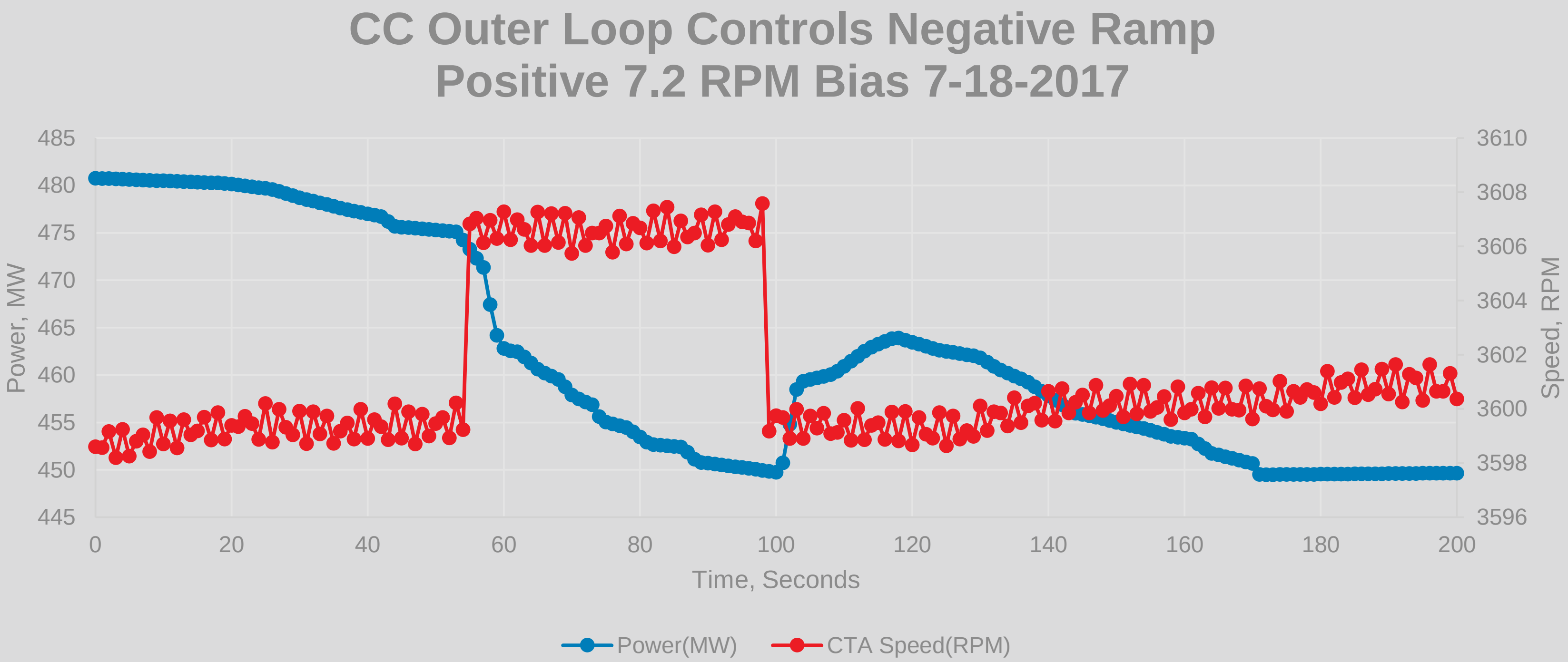
External Outer Loop Controls – Combine Cycle



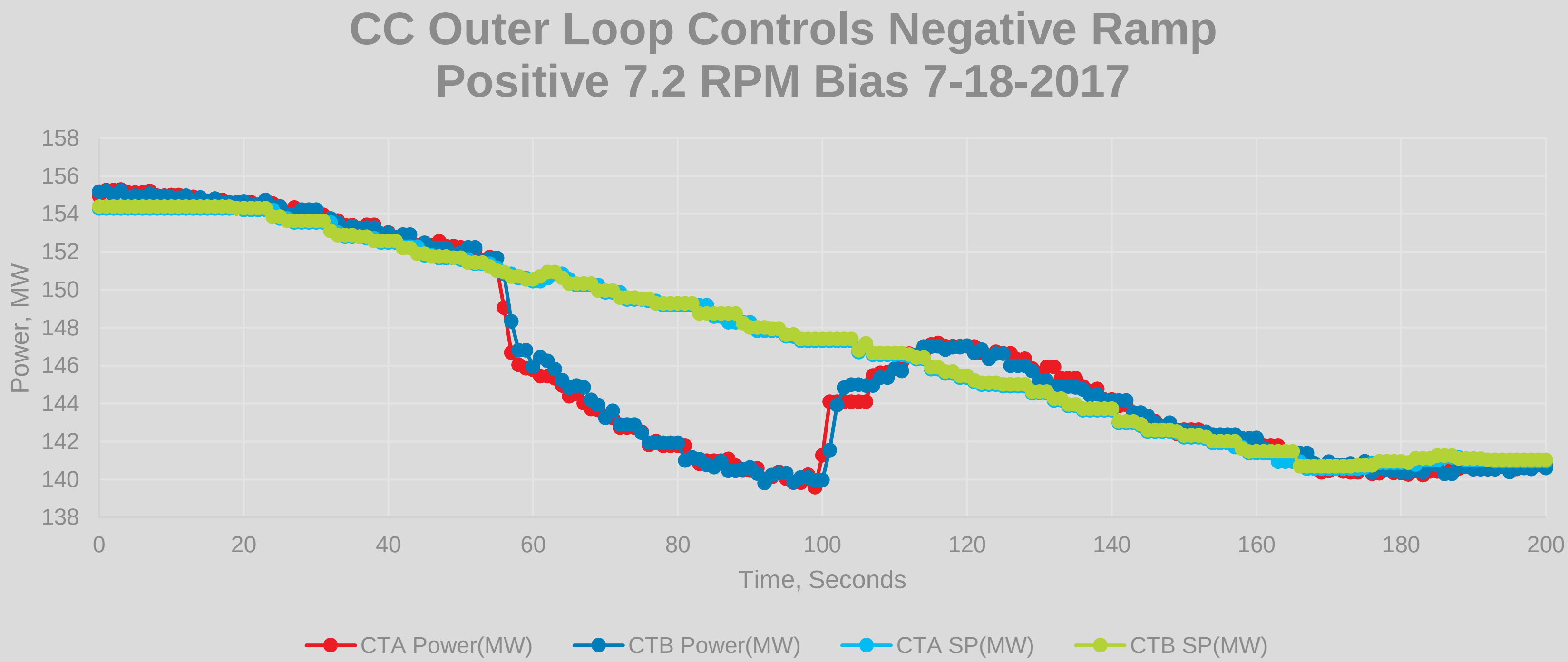
External Outer Loop Controls – Combine Cycle



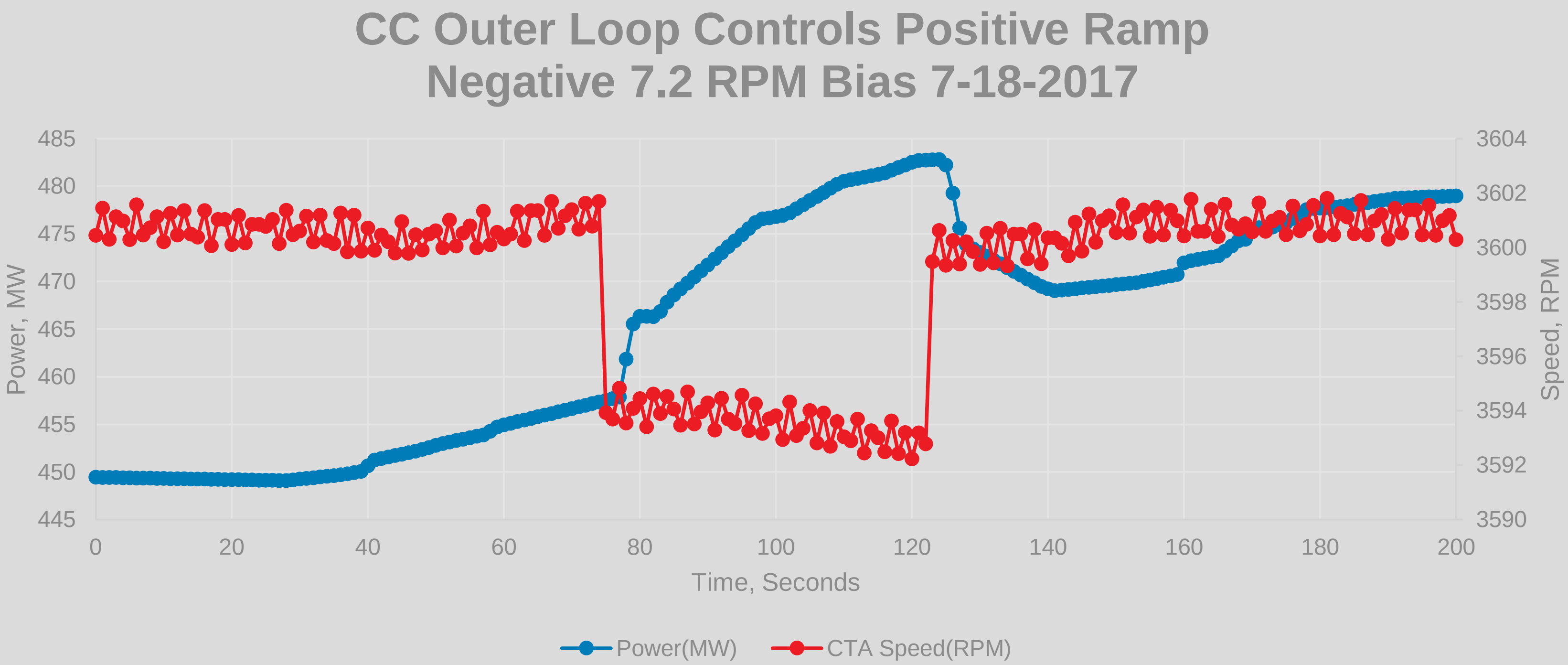
External Outer Loop Controls – Combine Cycle



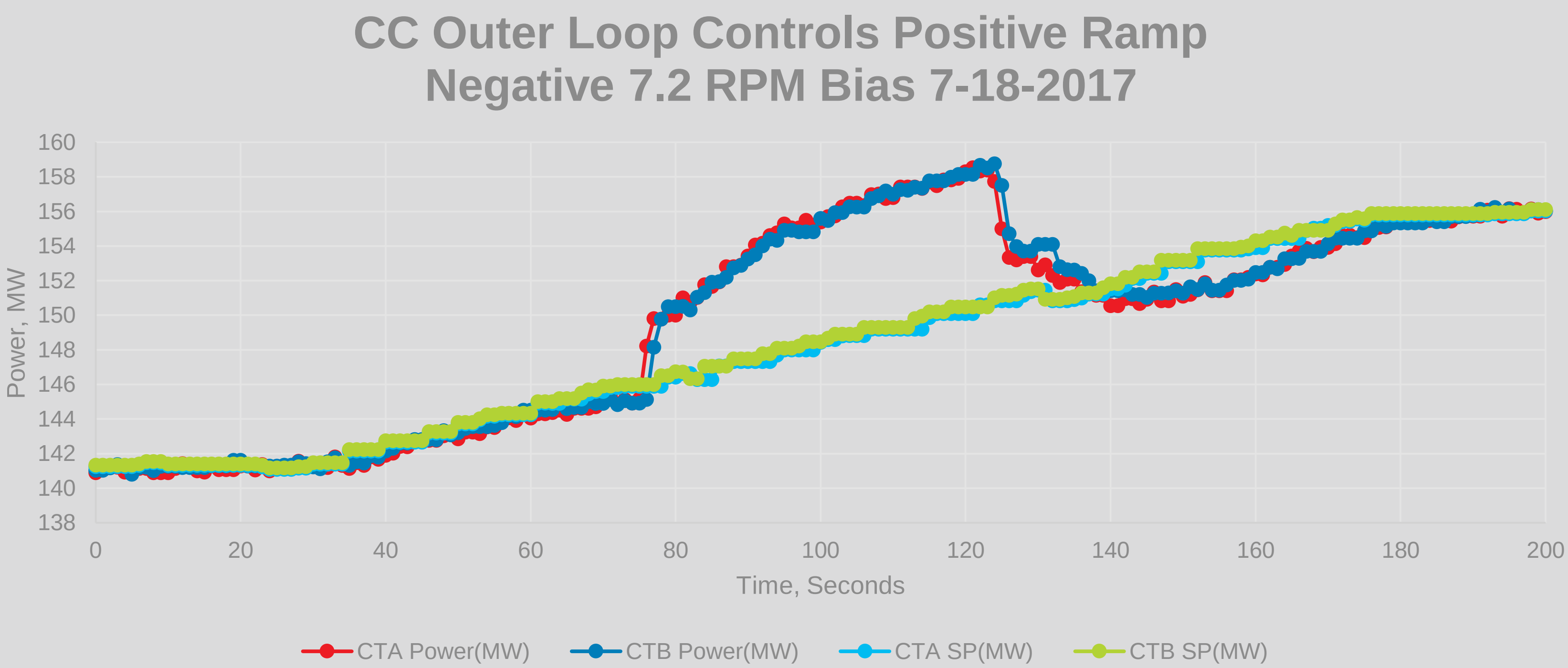
External Outer Loop Controls – Combine Cycle



External Outer Loop Controls – Combine Cycle



External Outer Loop Controls – Combine Cycle



Conclusions/Recommendations

- CT/CC Droop Operation
  - Turbine Controls Provides the Droop Response
  - Test to Verify the CT Responds as Desired to Frequency Events
    - Normal Operation
    - Ramping
    - In Base Mode and Just Below Base Mode
  - Test the Timing of Signals in the Outer Loop Control to Verify Desired Operation
  - Verify CT Setpoints From the Outer Loop Controls Perform as Desired during a Frequency Event

Other Considerations

- Combine Cycle Droop Calculations:
  - Entire Plant Droop Calculation is Dependent on Steam Turbine Output
  - CT's Carry All the Droop Response MW
    - If CT's MW Output is 182.5 MW and Steam is 170 MW, CC Droop is 5.86%
      - CT Droop %/MW = 4% / 182.5 MW = 0.02192 %/MW
      - Unit Droop = CT Droop %/MW * Total Unit Capacity MW / 2
      - Unit Droop = 0.02192 %/MW * 535 MW / 2 = 5.86%
    - If CT's MW Output is 182.5 MW and Steam is 294 MW, CC Droop is 7.22%
      - CT Droop %/MW = 4% / 182.5 MW = 0.02192 %/MW
      - Unit Droop = CT Droop %/MW * Total Unit Capacity MW / 2
      - Unit Droop = 0.02192 %/MW * 659 MW / 2 = 7.22%

Other Considerations

- Droop
  - For a 5% Droop with Deadband of 36 mHz:
    - +-3.0 Hz Frequency Deviation Results in +-100% Unit Output
  - Because the Droop Response is After Deadband:
    - +-3.036 Hz Frequency Deviation will Result in +-100% Unit Output
    - For a +-3.0 Hz Frequency Deviation Resulting in +-100% Unit Output the Droop will need to be 4.94% (3.0 - 0.036 / 60)

  - For a 4% Droop with Deadband of 36 mHz:
    - +-2.4 Hz Frequency Deviation Results in +-100% Unit Output
  - Because the Droop Response is After Deadband:
    - +-2.436 Hz Frequency Deviation will Result in +-100% Unit Output
    - For a +-2.4 Hz Frequency Deviation Resulting in +-100% Unit Output the Droop will need to be 3.94% (2.4 - 0.036 / 60)

Southern Company

Questions and Answers