Eastern Interconnection Planning Collaborative

Eastern Interconnection Planning Collaborative

Technical Committee

Frequency Response Task Force

2018 Final Report

Public Version

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Executive Summary

This report details information on the technical analysis, model modifications, and simulations performed by members of the Eastern Interconnection Planning Collaborative (EIPC) Frequency Response Task Force (FRTF) to assess the North American Electric Reliability Corporation (NERC) Essential Reliability Services Working Group (ERSWG) forward looking frequency Measures 1, 2, and 4 for the Eastern Interconnection (EI) for inclusion in the 2018 NERC Long-Term Reliability Assessment (LTRA).

With the addition of non-synchronous generation and planned synchronous resource retirements, questions have been raised about the ability of the EI to maintain frequency. The EIPC Technical Committee (TC) has been tasked with identifying and understanding how future generation contingencies could lead to Under Frequency Load Shedding (UFLS) events due to the reduction of frequency support from the changing generation resource mix. In order to study and plan for possible increased non-synchronous generation with reduced inertia, there is a need for improved frequency responsive power flow simulation models. With assistance from all of the FRTF members, biweekly meetings and collaborative efforts allowed the FRTF to develop, assign, and complete many tasks in support of this effort. The results of the analysis demonstrate the EI has sufficient system inertia over the next 5 years with planned resource retirements and non-synchronous resource additions.

In total, 13 tasks (described in Section 4) were completed. One of the tasks included benchmarking a historical frequency event with spring light load (SLL) cases to determine how the generator governor models performed in response to the simulated historical frequency events. Results concluded that the proportion of generators providing primary frequency response was higher than previous studies had determined. Based on efforts of the FRTF, approximately 45% of governors were modeled as in-service providing frequency response to match the historical frequency events. Previous studies from NERC suggested modeling roughly 30% of the governors in-service to benchmark against historical events. The FRTF determined this by visually comparing the simulation results with different percentages of governors disabled to the actual events. The results shown in Figure 6-6 and Figure 6-13 provided the best match to the actual events. For the forward looking frequency measures, 55% of the governors were disabled in the power flow model to match historical events.

A list of recommended changes to improve the frequency response of the planning models was developed as a result of this work and submitted for consideration to the Eastern Interconnection Reliability Assessment Group (ERAG) Multiregional Modeling Working Group (MMWG) in future model development cycles. It is expected future improvements to the modeling of governors through new compliance standards and updated simulation models from the software vendors will reduce the need for artificially disabling governor models to match historical performance.

The FRTF tested three different frequency events on a forward looking 2022 SLL MMWG power flow case. The events included the historical 4,500 MW event, the EI's Most Severe Single Contingency (MSSC), and the largest EI frequency event of the last 10 years. A 10,000 MW benchmark event was also tested to determine the amount of margin available in the EI system response. With 55% of the governors disabled based on the benchmarking analysis, generation power dispatch changes were made to the case to be similar to the lowest observed EI inertia event during 2017. The case also included future changes to synchronous generation retirements and non-synchronous generation additions expected in the next 5 years.

All three frequency events exhibited satisfactory frequency response with a minimum frequency (nadir) of 59.85 Hz, and the benchmark event had a nadir of 59.64 Hz. These are all significantly higher than the initial UFLS set point of 59.5 Hz. In other words, the system inertia and primary frequency response will be sufficient even with expected retirements of synchronous generation and increases in non-synchronous generation.

The results of the analysis were submitted for inclusion in the 2018 NERC LTRA. A set of recommendations for improvements to the MMWG case building process were also developed and the FRTF will work with the MMWG going forward to implement those recommendations. Details of the recommendations are described in Section 7.

- Recommendation #1: Modeling of Gross PMax Values in Case
- Recommendation #2: Accurate Governor Modeling in Case
- Recommendation #3: Addition of Frequency Responsive Dynamics Files to Library
- Recommendation #4: Need for New Low Inertia / Minimum Load MMWG Library Case

Section 1 Introduction

The Eastern Interconnection Planning Collaborative (EIPC) represents a first-of-its-kind effort that draws Planning Coordinators (PCs) in the Eastern Interconnection (EI) together in a collaborative effort to perform the technical analysis of transmission planning, related matters, and to model the impact on the grid of various energy policy options determined to be of interest by state, provincial, and federal policy makers and other stakeholders. The work EIPC undertakes builds upon, rather than replaces, the current local and regional transmission planning processes developed by the Planning Coordinators and associated regional stakeholder groups within the EI. Those processes may be informed by the EIPC analysis and efforts including the interconnection-wide review of existing regional plans and development of transmission options associated with the various energy policy options.

In response to a request from the North American Electric Reliability Corporation (NERC) Essential Reliability Services Working Group (ERSWG), the EIPC Technical Committee (TC) established the Frequency Response Task Force (FRTF) on July 20, 2017 to take a leadership role in providing the forward looking frequency response Measures 1, 2, and 4 from the Essential Reliability Services Task Force (ERSTF) Measurements Framework Report for the EI. Measures 1, 2, and 4 are discussed in Section 4 of this report.

As generation resource mix continues to evolve, maintaining the EI frequency is a concern because failure to do so could lead to increase in Under Frequency Load Shedding (UFLS) events. The scope of work outlined in this report was given a due date of July 31, 2018 for submission to the NERC Long-Term Reliability Assessment (LTRA). On April 11, 2018, members of the FRTF made a presentation to the EIPC TC. Feedback from the committee concluded that it is more important to meet the LTRA submission deadline than to fully complete the scope of work with a complete low inertia case following the NERC schedule revision for the LTRA. It was also confirmed after the presentation that FRTF members will complete all tasks without the use of an outside consultant.

Section 2 Background and Purpose

The FRTF was established by the EIPC Technical Committee to develop a low inertia future planning model of the EI used to analyze the frequency response characteristics and trends of the EI to specified large resource contingencies. As the generation resource mix continues to evolve based on new technologies, regulations, and policies, the ability of the EI to maintain system frequency will change. These changes have a potential to degrade the amount of frequency support within the EI. This potential degradation of frequency support within the EI could lead to an increase in the number of UFLS events which would be detrimental to the reliability of the system which is a concern to Planning Coordinators as well as NERC.

Furthermore, accurately assessing the impact of future possible resource mix changes depends on the accuracy of the currently available long-range planning models developed by the Eastern Interconnection Reliability Assessment Group (ERAG) Multiregional Modeling Working Group (MMWG). This linkage to available long-range planning models leads Planning Coordinators to provide constructive feedback on the models to assist MMWG in improving their accuracy and applicability to frequency response analyses under future system conditions.

The initial focus of the FRTF effort was to establish a baseline confidence in the solutions provided by currently available frequency response models and to provide suggestions to improve those models. The FRTF then developed models that adequately represented the behavior of the system to contingencies during time periods when the impact on frequency was and will be the largest. The objective was to benchmark the existing system and simulate the planned system 5 years into the future to calculate the frequency response metrics and trends of the EI to provide Measures 1, 2, and 4 to the NERC ERSTF for inclusion in the NERC LTRA report.

Section 3 Objectives

The objective of this effort is to determine the NERC Measures 1, 2, and 4 from the ERSTF Measures Framework Report for the EI.

- Measure 1: Synchronous Inertial Response (SIR) of EI – Measure of kinetic energy at the interconnection level. It provides both a historical and future (5-years-out) view.
- Measure 2: Initial Frequency Deviation Following Largest Contingency – At minimum SIR conditions from Measure 1, determine the frequency deviation within the first 0.5 seconds following the largest contingency (as defined by the Resource Contingency Criteria [RCC] in BAL-003-1 for each interconnection).
- Measure 4: Frequency Response at Interconnection Level – Measure 4 is a comprehensive set of frequency response measures at all relevant time frames: Point A to C frequency response in MW/0.1 Hz, Point A to B frequency response in MW/0.1 Hz (similar to ALR1-12), C:B Ratio, C:C' Ratio as well as three time-based measures (t_0 to t_C, t_C to $t_{C'}$, and t_0 to $t_{C'}$), capturing speed of frequency response and response withdrawal.

In addition to calculating the ERSTF frequency measures, the FRTF developed a set of recommendations to augment the current MMWG model building process to create study-ready low inertia cases to calculate frequency measures. Details on each recommendation are in Section 7. The results of Measures 1, 2, and 4 are provided in Section 6.11.

Section 4 Tasks

The process used by the FRTF included reviewing current research on frequency response, selecting historical low inertia events, calculating inertia of historical events, benchmarking existing models, and simulating future conditions with low generation inertia. In total, 13 tasks were created and task force members volunteered to complete each task. Details for each task are shown below.

4.1 Task 1 – Review of Current Research

The University of Tennessee, Knoxville (UTK) in collaboration with the Oak Ridge National Laboratory has performed a significant amount of work in validating the frequency response of standard MMWG models. Based on their initial work on validation of the models, they have also started to investigate the impacts of higher penetrations of solar photovoltaic (PV) generation. In addition, NERC Staff has completed a significant amount of work to simulate actual disturbances and attempt to replicate historical events. The reports of most interest are:

- Frequency Response Assessment and Improvement of Three Major North American Interconnection due to High Penetrations of Photovoltaic Generation – Phase One
- Dynamic Model Validation with Governor Dead band on the Eastern Interconnection
    - http://info.ornl.gov/sites/publications/files/Pub48114.pdf
- NERC Frequency Response Initiative Report
    - http://www.nerc.com/docs/pc/FRI_Report_10-30-12_Master_w-appendices.pdf

4.2 Task 2 – Develop Script to Calculate Inertia

Using python, FRTF created a script to calculate the equivalent system inertia using the MMWG Spring Light Load (SLL) power flow cases for 2018 and 2022. Equivalent inertia can be calculated using the following methods:

- Model Parameter Based
    a. By looking at the case dispatch and maximum capability of the units as well as H the inertia constant [inertia is defined as the product of MVA and H and has the units of MVA-s]
    b. Determine the equivalent r (governor regulation) taking into account the units that are at maximum have a value of r=infinity (meaning no governor gain as the gain is 1/r)

4.3 Task 3 – Select Historical Low Inertia and Frequency Events

Using historical data obtained from FNET[1] a set of historical events (initially limited to 2 frequency events) was selected which had recorded frequency excursions. After the events were selected, it was determined whether or not these events occurred during time periods that generally align with the time frames modeled by MMWG in the 2018 SLL model. For those historical events, digital fault recorder (DFR) or phasor measurement unit (PMU) data was used and the equivalent system inertia was calculated. This DFR/PMU data was also used to benchmark the MMWG case performance. A third time period of the lowest recorded historical inertia of the EI for 2017 was selected based on NERC data. For the three time periods that were selected, each PC provided the resource mix into 8 categories (nuclear, coal, natural gas combined cycle, natural gas simple cycle, hydro, wind, solar, and other). Later it was determined to add a 9th category of pumped storage.

4.4 Task 4 – Collect Historical Dispatch Data

Based on the dates selected for the historical low inertia and frequency events, each Planning Coordinator collected the unit dispatch for the three time periods. This historical dispatch was used to identify the overall resource mix and type of generation participating in the primary frequency response for the EI and sub-regions during the times selected. It was determined that pumping stations would be included in the inertia calculation but would not be included as loads. To do this, each member included pumping stations as negative generation. The total load and generation for each Region/Area was included. Each generation inertia constant was used to calculate the total generation inertia in MVA-s. Due to confidentiality reasons, the specific dispatch data for each generator was not submitted but was used as a guide by each PC to create a dispatch that was similar in composition to the three time periods.

4.5 Task 5 – Benchmark Historical Frequency Event

The FRTF conducted a benchmark comparison of two of the historical frequency events chosen in Task 3. The two events selected in Task 3 had similar load levels to the 2018SLL library case. The benchmark compared the closest SLL MMWG case with a focus on identifying the resource mix and amount of generation participating in the frequency response. Members submitted modifications for their areas which included load and generation mix changes. FRTF members volunteered to collect all the files and apply them to the 2018SLL MMWG case to get a case which resembled the generation and load for each event. After dispatch data was collected in Task 4 and applied to the 2018SLL case the historical frequency events were benchmarked with the FNET recorded data. To get the simulated case response closer to the recorded event, governor models were turned off in several percentage steps.

[1] Operated by the Power Information Technology Laboratory at the University of Tennessee, FNET is a low-cost, quickly deployable GPS synchronized wide-area frequency measurement network. High-dynamic accuracy DFRs are used to measure the frequency, phase angle, and voltage of the power system at ordinary 120 V outlets. The measurement data are continuously transmitted via the Internet to the FNET servers hosted at the University of Tennessee and Virginia Tech.

4.6 Task 6 – Identify Any Gaps in the Models

The FRTF identified gaps in the MMWG models based on the results of research performed by UTK and NERC reviewed in Task 1, and the benchmarking of historical events to actual system response completed in Task 5.

4.7 Task 7 – Identify Potential Improvements to Model Development Practices

Based on the gaps identified in Task 6, the FRTF developed 4 recommendations to improve the modeling practices of the MMWG in order to better model the expected system response. These recommendations are specific, actionable, and have an initial expected implementation time. Recommendations are described in Section 7.

4.8 Task 8 – Develop Process to Select Frequency Events to Test for the EI

To capture the trend of frequency response in the EI, the PCs tested three different contingencies. The first was the largest historical event seen on the EI in which 4,500 MW were tripped. The second was the largest historical event within the past 10 years which occurred on April 27, 2011. The final event was the MSSC for the EI as defined by the RCC in NERC Standard BAL-002-2(i) Requirement R2.[2]

4.9 Task 9 – Develop a List of Changes for Forward Looking Frequency Case

Information was gathered from research in Task 1 and the results of Tasks 5, 6, and 7 for frequency response in the EI. Per research performed by UTK, there are various components that need to be trended to enhance the traditional frequency response metric (ALR1-12). The various components per (ERSTF Framework Report, 2015[3]) are described in Appendix C.

4.10 Task 10 – Apply Changes Outlined in Task 9 to Forward Looking Case

From the changes developed in Task 9, the future 5-years-out MMWG 2022SLL case was modified so that it represented an expected future low inertia case. These changes were supplied by the FRTF members and are based on projected changes to the generation resource mix projected to occur by 2022. The MMWG produced a version of the 2022SLL case which included disabled and squelched governor response for many generators in the EI. While this case was used as a starting point for these simulations, test event simulations were performed to determine the change in frequency response associated with these changes. Additionally, the governor model changes used to match the 2018SLL case to the benchmark event were applied to compare against the starting point cases.

4.11 Task 11 – Calculate ERSTF Measures 1, 2, and 4

The frequency response of the EI was simulated to postulated resource contingencies. Frequency versus time was plotted for each contingency defined in Task 8:

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[2] http://www.nerc.net/standardsreports/standardssummary.aspx

[3] https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF%20Framework%20Report%20-%20Final.pdf

- The simultaneous 2007 outage of 4,500 MW which represents the largest historic simultaneous resource loss for the EI
- The largest simultaneous resource loss for the EI for the last 10 years
- The MSSC for the EI
- Simulated 10,000 MW loss event for benchmark purposes

The frequency values were modeled in a manner consistent with the methodology utilized by FNET. The task force collected other pertinent information from the dynamics simulations needed to calculate the frequency response tests outlined in Measures 1, 2, and 4 of the ERSTF report.

4.12 Task 12 – Write an Internal EIPC Report and Submission to NERC LTRA of Results

This report has been written to document the findings of the effort. The report includes detailed information on the efforts performed by members of the FRTF. The information in this report is being used to create a process manual to guide future efforts. A separate submission was made based on a template provided from NERC to provide results for the ERS Measures 1, 2, and 4 for inclusion in the 2018 LTRA.

4.13 Task 13 – Outreach to Other Interconnections

Work with other interconnections and NERC to understand how the other interconnections are developing the same information and share results from the FRTF work.

Section 5 Schedule

The FRTF held biweekly calls during the course of the project. During meetings, members discussed action items from previous meetings and current status of work on each task. The timeline for each task is shown below.

- December 31, 2017 – Complete literature review of EI frequency response studies (Task 1)
- January 10, 2018 – Create script to calculate system inertia of a power flow case (Task 2)
- March 31, 2018 – Select Historical Events and collect historical data (Task 3)
- April 30, 2018 – Collected historical dispatch (Task 4)
- May 31, 2018 – Complete dispatch comparison (Task 5)
- May 31, 2018 – Finalize Gap List (Task 6)
- May 31, 2018 – Finalize Suggested Modeling Improvements (Task 7)
- April 30, 2018 – Document largest 10-year and MSSC contingencies for EI (Task 8)
- May 31, 2018 – Finalize list of changes (Task 9)
- July 31, 2018 – Finalize future case to perform analysis (Task 10)
- July 31, 2018 – Finalize results of Measures 1, 2, and 4 (Task 11)
- July 15, 2018 – NERC LTRA Submission (Task 12)
- December 31, 2018 – Final EIPC Report (Task 12)

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Section 6 Results

6.1 Task 1 – Review of Current Research

The FRTF reviewed the reports described in Section 4.1 to determine what recommendations can be applied to the future MMWG models and may be helpful in developing the low inertia model needed for analysis in later Tasks. The FRTF held a web conference with UTK and NERC study representatives to better understand their work. The FRTF also reviewed and considered other studies, beyond the UTK and NERC work which are referenced at the end of this document in Appendix A: Review of Current Research.

6.2 Task 2 – Develop Script to Calculate Inertia

Using the python programming language, the FRTF created a script to calculate the equivalent system inertia of two MMWG power flow cases. The output of the script for both cases is shown in Table 6-1.

Table 6-1: Calculated Parameters

	MMWG_2018SLL_2017Series	MMWG_2022SLL_2017Series
Sum of PMax (MW)	346,722.717	336,482.608
Sum of PGen (MW)	276,342.105	268,039.632
Equivalent H (s)	3.892	3.942
Equivalent R (pu)	0.208	0.142
Spinning Reserve (%)	25.469	25.535
Sum of MBase (MVA)	427,343.312	413,198.917
System Inertia (MVA-s)	1,663,191.977	1,628,795.864
Beta in pu of MBase	4.812	7.021
Beta in units of MW/Hz	34,274.024	48,354.171

6.3 Task 3 – Select Historical Low Inertia and Frequency Events

The FRTF agreed to select one low inertia historical event and two historical frequency events. The selected low inertia historical event was on May 7, 2017 at 02:43:00 EDT. This event was based on NERC Resource Subcommittee (RS) data that records the EI inertia and system load throughout time. The two historical frequency events were on February 24, 2017 at 22:52:42 EST and April 8, 2017 at 11:52:47 EDT. These events were from the FNET database that records frequency events that occur on the EI. Each event contained credible generation dispatch and inertia which was used for assumed resource mix in the future models.

6.4 Task 4 – Collect Historical Dispatch Data

Data was then collected for each event selected in Task 3. FRTF members submitted excel files with information for generation and load for all areas in the EI. Due to confidentiality reasons, the specific dispatch data for each generator was not submitted. In each of these, the resource mix was originally separated into 8 categories (nuclear, coal, natural gas CC, natural gas simple cycle, hydro, wind, solar, and other). In biweekly meetings, it was determined to add a 9th category of pumped storage. Members agreed to include pumped storage as negative generation and include the machine inertia as a positive value in the total inertia calculation. Pumped storage was not counted as load. Details for the events are shown in Table 6-2.

Table 6-2: Historical Resource Mix by Type (%)

Event	Nuclear	Coal	NG CC	NG SC	Hydro	Wind	Solar	Other	Pump
02/24/17 @ 2252	28	30	25	4	3	9	0	1	0
04/08/17 @ 1152	26	31	21	5	4	11	1	1	0
05/07/17 @ 0243	33	28	21	4	5	9	0	2	-2

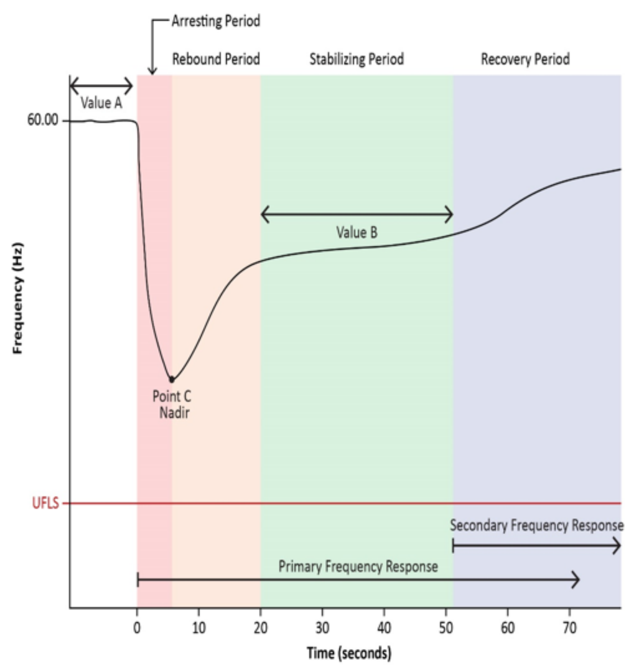
6.5 Task 5 – Benchmark Historical Frequency Event

Figure 6-1 includes a sample frequency response plot from the ERSTF report[4] which shows how frequency response is calculated and frequency deviation due to generation loss. Values A, B, and C are each described in Figure 6-1.

Figure 6-1: Frequency Response Data Point Explanations

This figure illustrates a frequency deviation due to a loss of generation resource and the methodology for calculating frequency response. **The event starts at time t0**. **Value A is the average frequency from t-16 to t-2 seconds, Point C is the lowest frequency point observed in the first 12 seconds and Value B is the average from t+20 to t+52 seconds. Point C' occurs when the frequency after 52 seconds falls below either the Point C (12 seconds) or average Value B (20 – 52 seconds).**

The difference between Value A and Value B is the change in frequency used for calculating primary frequency response. Frequency response is calculated as the ratio of the megawatts lost when a resource trips and the frequency deviation. For convenience, frequency response is expressed in this report as an absolute value. A large absolute value of frequency response, measured in MW/0.1Hz, is better than a small value.



The two historical frequency events selected in Task 3 were benchmarked in Task 5 by members of the FRTF. These events were considered "Off the Shelf" cases. The event on April 8, 2017 at 15:52:47 EDT resulted in the loss of 1,195 MW. Figure 6-2, which was provided by NERC, shows the frequency plot.

[4] https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF%20Framework%20Report%20-%20Final.pdf

NERC also provided FNET raw data of the event. The FRTF used this data to create the plot shown in Figure 6-3. Through conversations between FRTF members and NERC, the data plotted in Figure 6-2 and Figure 6-3 is via FNET which is from multiple frequency recorders. In Figure 6-2 and Figure 6-3, generation trips at approximately 60 seconds. The loss of 1,195 MW is represented as point A and point C represents nadir which occurs 10.8 seconds after the unit was tripped.

Figure 6-4 is the April 8, 2017 event simulation performed by the FRTF. The simulation plot uses the same scale and measurements (points A, B, and C) as the plot in Figure 6-2 and Figure 6-3. This simulation also includes all governors in-service with exception to 8 WEHGOV models which caused PSS/E to crash when the generator real power output was near its upper limit. These 8 WEHGOV governor models were disabled initially to run the simulation. Table 6-1 shows the frequency event measurements and

Table 6-3 shows the simulation results. A few observations include timing and frequency differences between the event and simulation. In the simulation, nadir is reached faster than in the actual event. The simulation also differs from the event in frequency recovery. The frequency remains higher during the arresting period in the simulation. However, in the rebound period, the stabilizing period, and the recovery period the actual event shows better results than the simulation. Figure 6-3, Figure 6-4, Figure 6-5, Figure 6-6, and Figure 6-7 also include the April 8, 2017 event simulation without the MMWG frequency response modeling changes applied.

Figure 6-5 is with 70% of the governors in-service. Table 6-5 shows the simulation results with 70% of the governors in-service. With approximately 70% of the governors in-service, the plot is closer to Figure 6-2 and Figure 6-3 than with all governors in-service but the frequency recovers too quickly. Figure 6-6 is with 45% of the governors in-service. Table 6-6 shows the simulation with 45% of the governors in-service and Figure 6-7 is with 30% of the governors in-service. Table 6-7 shows the simulation with 30% of the governors in-service.

All simulations are run at steady state for 60 seconds which is similar to the actual events in Figures 6-2 and 6-3.

Figure 6-2: EI FNET April 8, 2017 Event

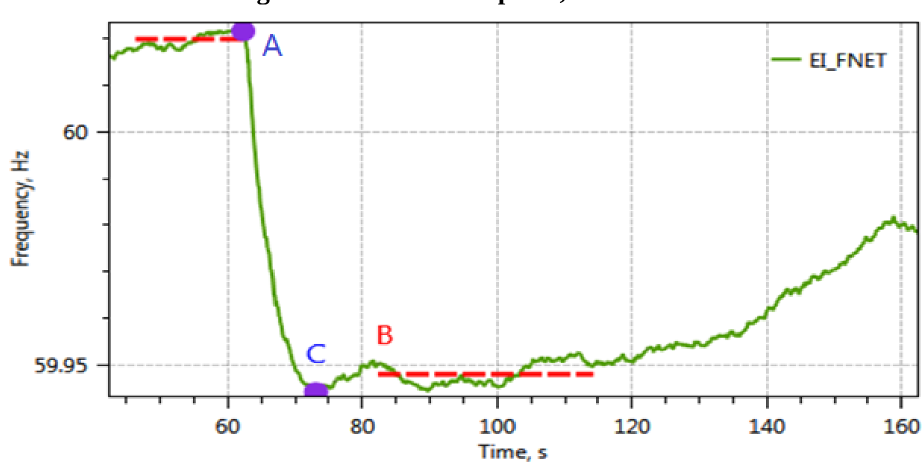


Figure 6-3: EI FNET April 8, 2017 Event Raw Data Plot

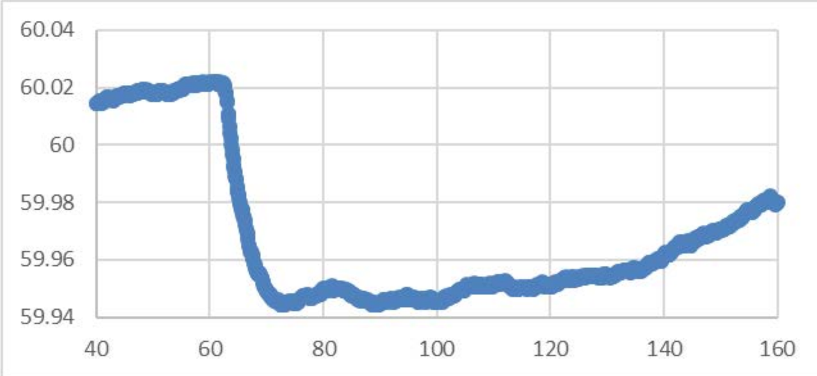


Table 6-3: April 8, 2017 Frequency Event (Figure 6-2 and Figure 6-3)

April 8, 2017 Event	A (Hz)	B (Hz)	C (Hz)	C’ (Hz)	Freq. Resp. (Current) [MW/0.1Hz]	Freq. Resp. (Nadir) [MW/0.1Hz]	C:B Ratio	C’:C Ratio
	60.02	59.948	59.944	-	1660	1574	1.06	-
Time-Based Measures	**A (s)**	**B (s)**	**C (s)**	**C’ (s)**	**tc-t0 (s)**	**tc’-tc (s)**	**tc’-t0 (s)**	
	0	-	10.8	-	10.8	-	-	

Figure 6-4: 2017/04/08 w/o Frequency idv: All Governors In-service

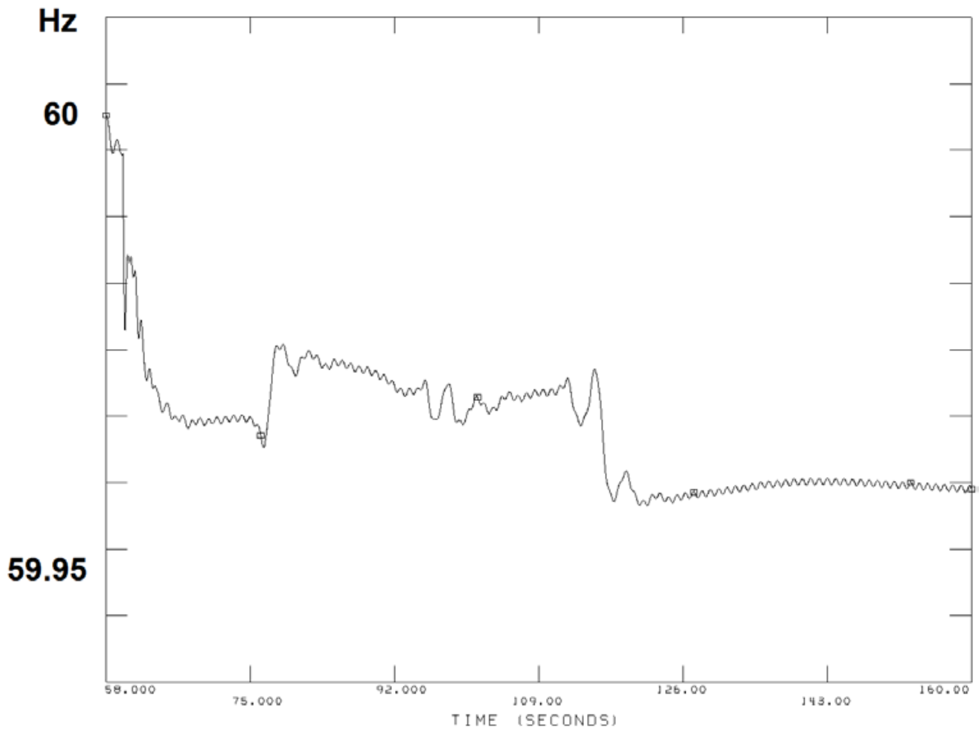


Table 6-4: April 8, 2017 Benchmark: All Governors In-Service (Figure 6-4)

Benchmark Simulation	**A (Hz)**	**B (Hz)**	**C (Hz)**	**C' (Hz)**	**Freq. Resp. (Current) [MW/0.1Hz]**	**Freq. Resp. (Nadir) [MW/0.1Hz]**	**C:B Ratio**	**C':C Ratio**
	60.01	59.979	59.975	59.977	3854.84	3414.29	1.13	0.94
Time-Based Measures	**A (s)**	**B (s)**	**C (s)**	**C' (s)**	**tc-t0 (s)**	**tc'-tc (s)**	**tc'-t0 (s)**	
	0	-	7.9	53.17	7.9	45.27	53.17	

Figure 6-5: 2017/04/08 w/o Frequency idv: 70% of Governors In-service

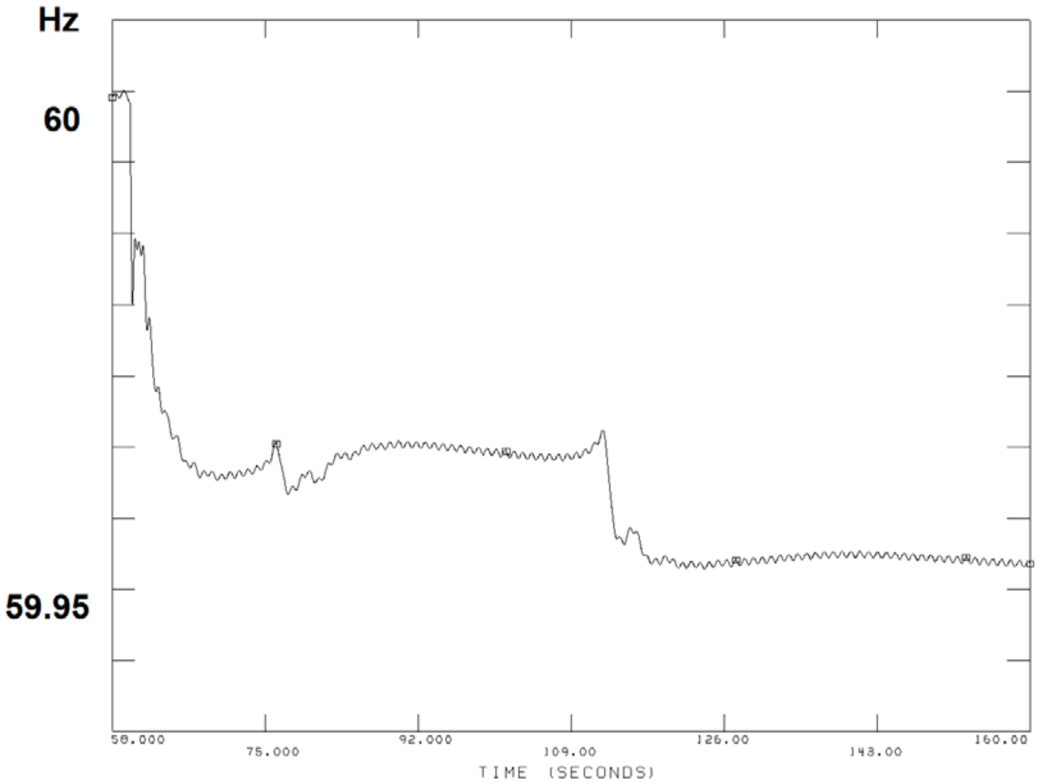


Table 6-5: April 8, 2017 Benchmark: 70% of Governors In-Service (Figure 6-5)

Benchmark Simulation	A (Hz)	B (Hz)	C (Hz)	C' (Hz)	Freq. Resp. (Current) [MW/0.1Hz]	Freq. Resp. (Nadir) [MW/0.1Hz]	C:B Ratio	C':C Ratio
	60.02	59.975	59.989	59.973	2655.56	3854.84	0.69	1.52
Time-Based Measures	**A (s)**	**B (s)**	**C (s)**	**C' (s)**	**tc-t0 (s)**	**tc'-tc (s)**	**tc'-t0 (s)**	
	0	-	9.7	53.17	9.7	43.47	53.17	

Figure 6-6: 2017/04/08 w/o Frequency idv: 45% of Governors In-service

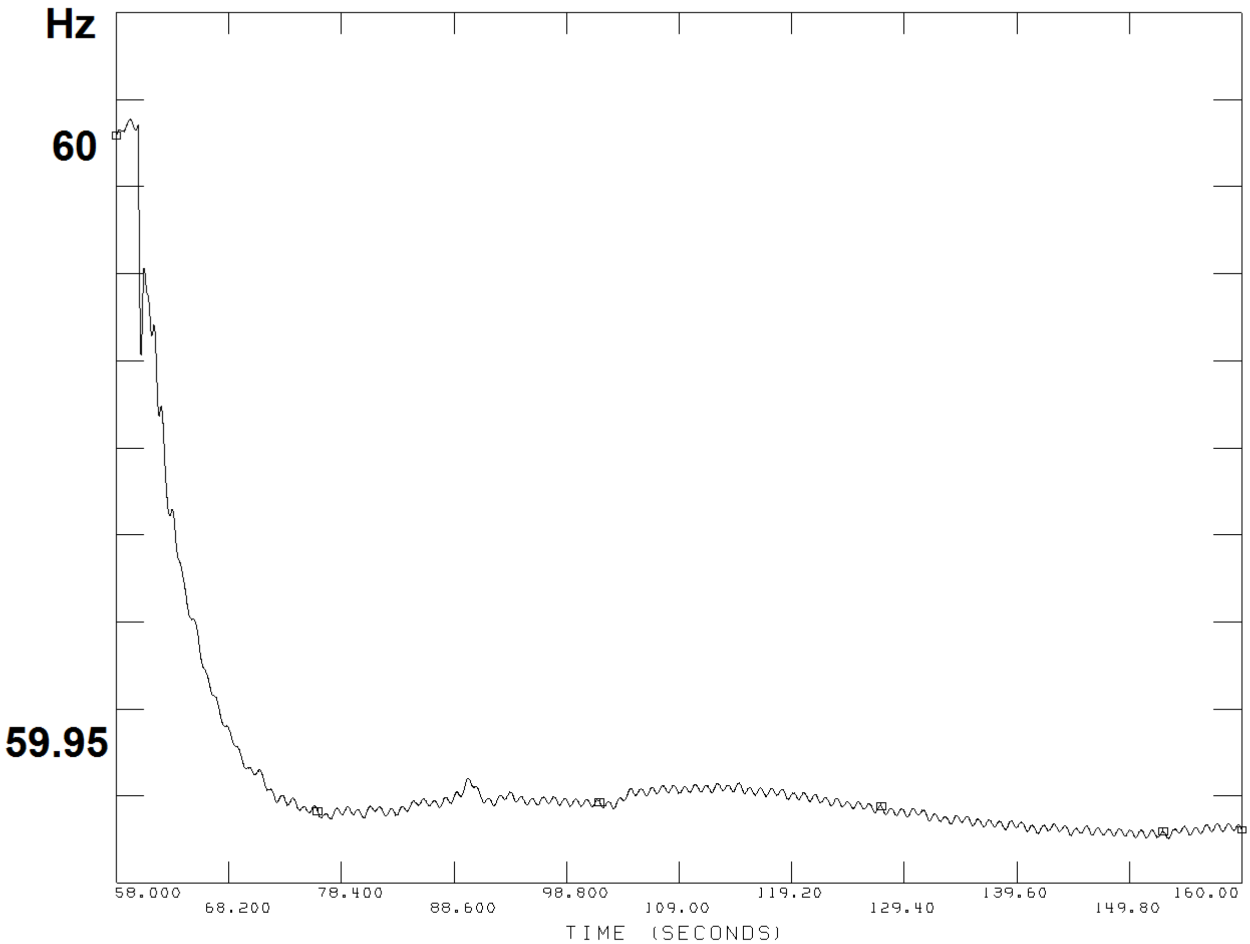


Table 6-6: April 8, 2017 Benchmark: 45% of Governors In-Service (Figure 6-6)

Benchmark Simulation	A (Hz)	B (Hz)	C (Hz)	C' (Hz)	Freq. Resp. (Current) [MW/0.1Hz]	Freq. Resp. (Nadir) [MW/0.1Hz]	C:B Ratio	C':C Ratio
	60.02	59.949	59.949		1683.10	1683.10	1.00	1.01
Time-Based Measures	**A (s)**	**B (s)**	**C (s)**	**C' (s)**	**tc-t0 (s)**	**tc'-tc (s)**	**tc'-t0 (s)**	
	0	-	11.9	59.05	11.9	47.15	59.05	

Figure 6-7: 2017/04/08 w/o Frequency idv: 30% of Governors In-service

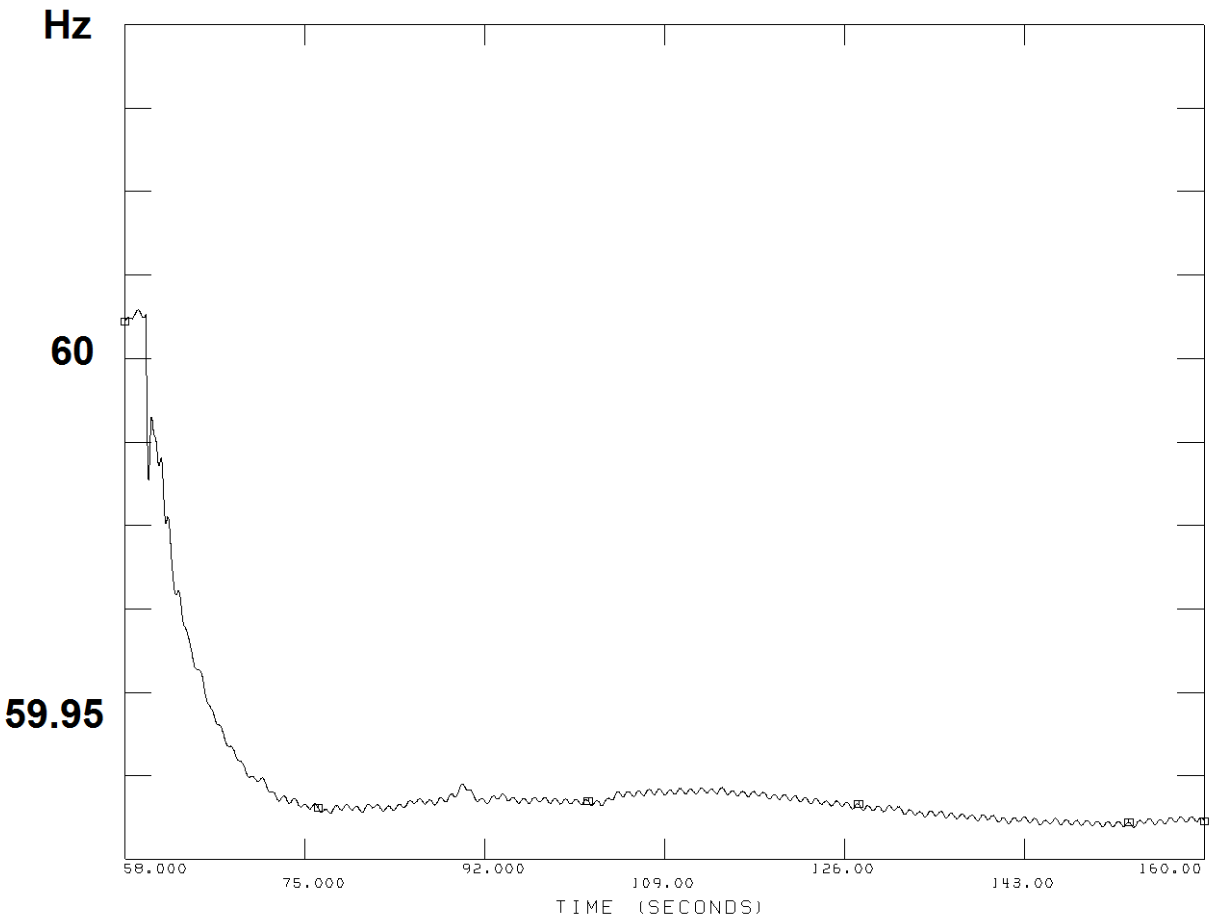


Table 6-7: April 8, 2017 Benchmark: 30% of Governors In-Service (Figure 6-7)

Benchmark Simulation	**A (Hz)**	**B (Hz)**	**C (Hz)**	**C' (Hz)**	**Freq. Resp. (Current) [MW/0.1Hz]**	**Freq. Resp. (Nadir) [MW/0.1Hz]**	**C:B Ratio**	**C':C Ratio**
	60.05	59.952	59.967	59.951	1219.39	1439.76	0.85	1.19
Time-Based Measures	**A (s)**	**B (s)**	**C (s)**	**C' (s)**	**tc-t0 (s)**	**tc'-tc (s)**	**tc'-t0 (s)**	
	0	-	11.7	52.84	11.7	41.14	52.84	

Figure 6-8: 2017/04/08 w/ Frequency idv: All Other Governors In-service

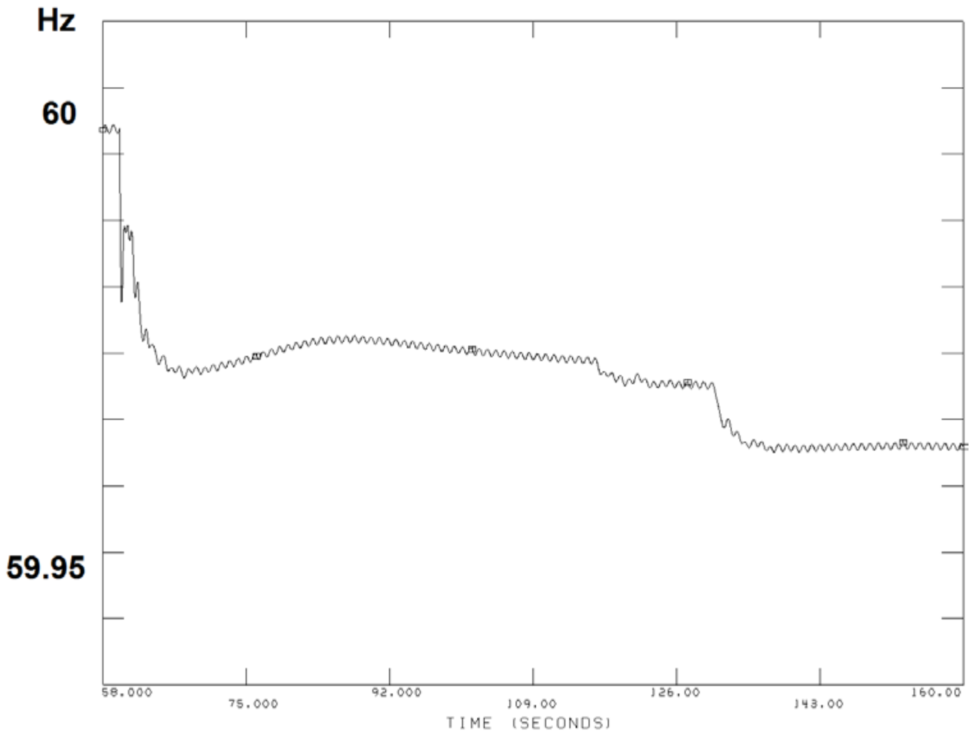
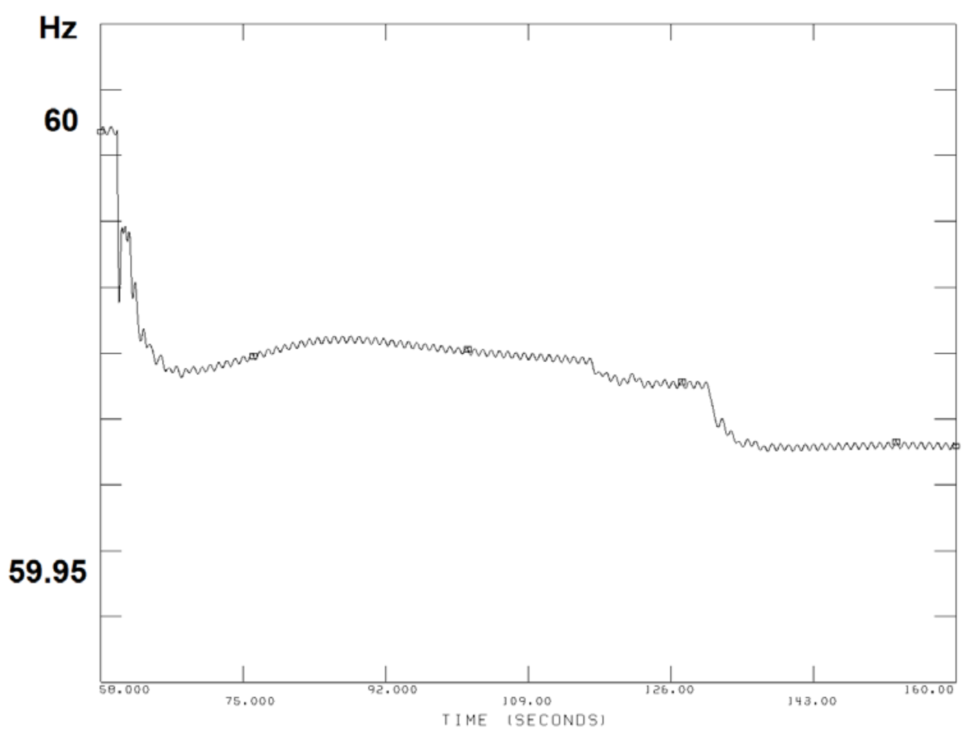


Figure 6-9: 2017/04/08 w/ Frequency idv: 45% of Other Governors In-service



After completing the simulations for the April 8, 2017 event, the event on February 24, 2017 which was a loss of 850 MW, was simulated using the April 8, 2017 simulation case, due to the proximity in time between the two events. The generation dispatch was adjusted for the February 24, 2017 simulation to correspond to actual conditions. The generation dispatch was adjusted to better match that of the generation located near the tripping of generation. Figure 6-10 and Figure 6-11 show the actual February 24, 2017 event and Figure 6-12 and 6-13 show the simulations. In Figure 6-12, the event is simulated without the MMWG Frequency Response idv and all governors in-service. In Figure 6-13, the simulation is also without the MMWG Frequency Response idv but only 45% of the governors in-service. The plot in Figure 6-13 is consistent with the actual event and provides the best fit. Table 6-8, Table 6-9, and 6-10 include detailed information on the February 24, 2017 event and simulations.

Figure 6-10: EI FNET February 24, 2017 Event

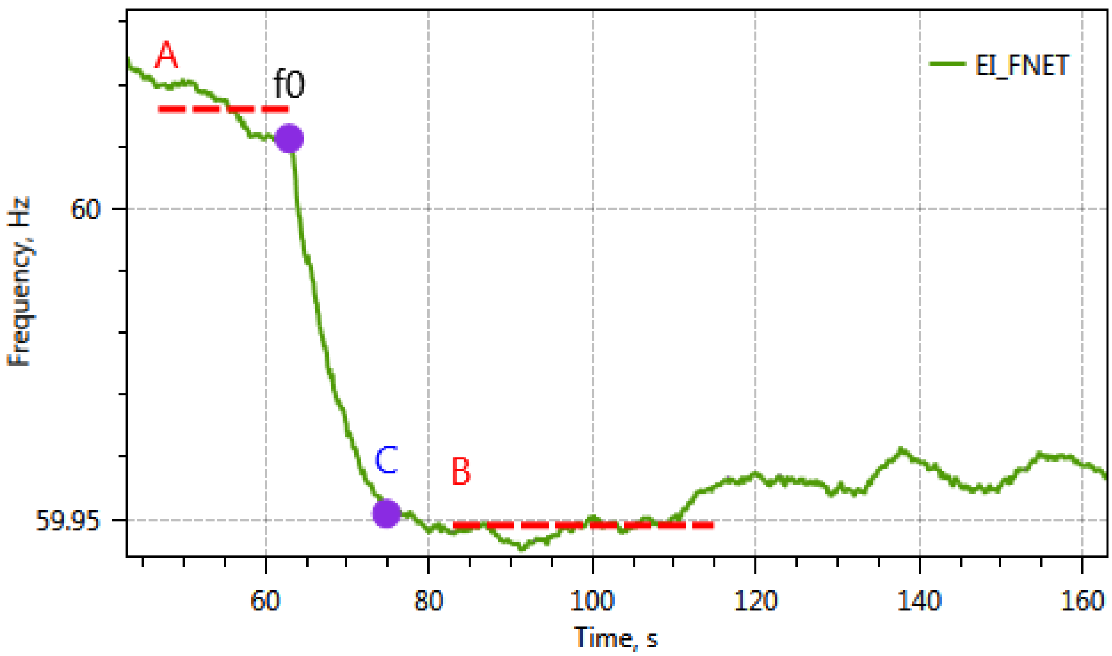


Figure 6-11: EI FNET February 24, 2017 Event Raw Data Plot

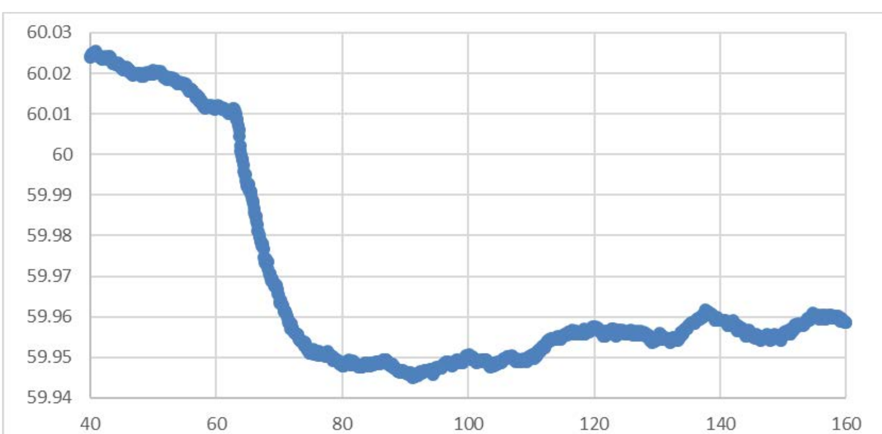


Table 6-8: February 24, 2017 Event (Figure 6-10 and Figure 6-11)

February 24, 2017 Event	A (Hz)	B (Hz)	C (Hz)	C' (Hz)	Freq. Resp. (Current) [MW/0.1Hz]	Freq. Resp. (Nadir) [MW/0.1Hz]	C:B Ratio	C':C Ratio
	60.016	59.949	59.9509	-	1269	1306	0.97	-
Time-Based Measures	**A (s)**	**B (s)**	**C (s)**	**C' (s)**	**tc-t0 (s)**	**tc'-tc (s)**	**tc'-t0 (s)**	
	0	-	11.9	-	11.9	-	-	

Figure 6-12: 2017/02/24 w/o Frequency idv: All Governors In-service

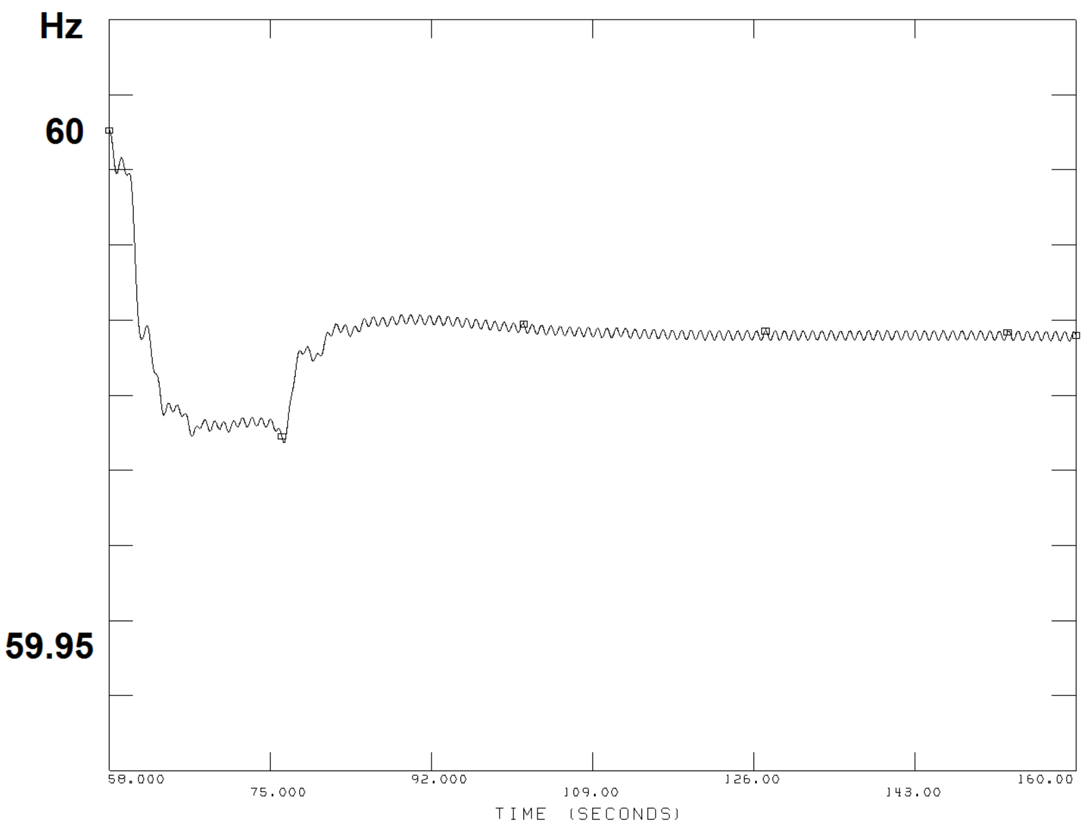


Table 6-9: February 24, 2017 Benchmark All Governors In-Service (Figure 6-12)

Benchmark Simulation	A (Hz)	B (Hz)	C (Hz)	C' (Hz)	Freq. Resp. (Current) [MW/0.1Hz]	Freq. Resp. (Nadir) [MW/0.1Hz]	C:B Ratio	C':C Ratio
	60.017	59.993	59.978	59.978	3854	2371	1.63	1.00
Time-Based Measures	**A (s)**	**B (s)**	**C (s)**	**C' (s)**	**tc-t0 (s)**	**tc'-tc (s)**	**tc'-t0 (s)**	
	0	-	6.6	52	6.6	45.4	52	

Figure 6-13: 2017/02/24 w/o Frequency idv: 45% of Governors In-service

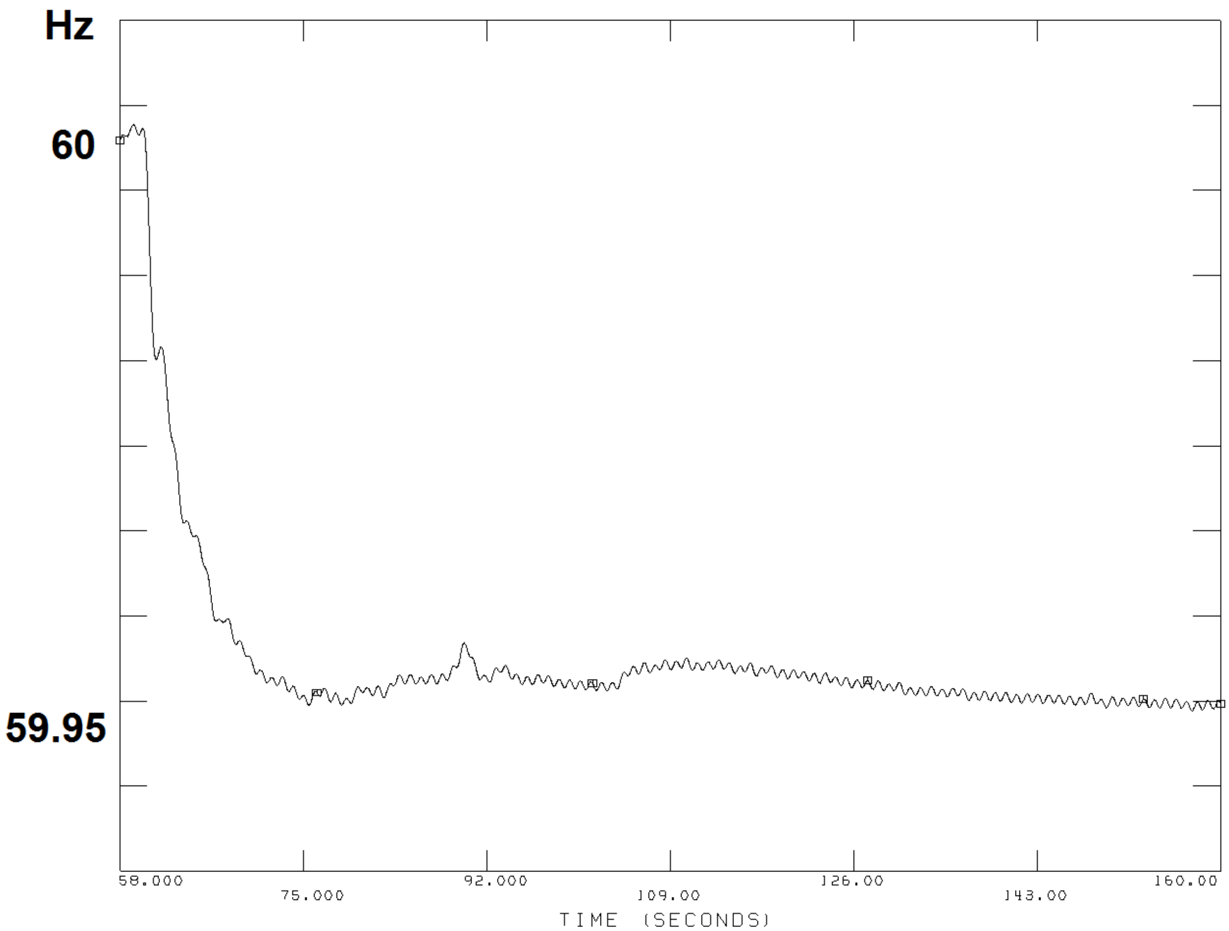


Table 6-10: February 24, 2017 Benchmark 45% of Governors In-Service (Figure 6-13)

Benchmark Simulation	A (Hz)	B (Hz)	C (Hz)	C' (Hz)	Freq. Resp. (Current) [MW/0.1Hz]	Freq. Resp. (Nadir) [MW/0.1Hz]	C:B Ratio	C':C Ratio
	60.019	59.961	59.960	59.960	1594	1567	1.02	1.00
Time-Based Measures	**A (s)**	**B (s)**	**C (s)**	**C' (s)**	**tc-t0 (s)**	**tc'-tc (s)**	**tc'-t0 (s)**	
	0	-	11.3	52	11.3	40.7	52	

6.6 Task 6 – Identify Any Gaps in the Models

The EI assessed the results of 2017 Series MMWG model building process that introduced fully response, squelched, and non-responsive modifications to the base case which resulted in the production of a MMWG frequency response idv. This idv file was used to perform the simulations shown in Figure 6-8 and Figure 6-9. In this idv file, many models that are considered non-responsive are removed. Other plant-related models are added or replaced for certain machines with this file. The FRTF concluded that while these efforts are warranted, additional refinement of the approach should be developed before utilizing these representations in the model for forward looking frequency response analysis.

The FRTF also made an effort to identify gaps in the cases used for this frequency response study. Much work was completed by others with respect to data quality for frequency response studies. The FRTF reviewed a number of studies and reports related to this, such as the work done by the UTK, Lawrence Berkley National Labs, NERC, and others. This previous work provided valuable input into the process the FRTF used to conduct this study. It is not our intent to reiterate the findings and recommendations of previous efforts. Instead, the focus was to identify some of the "data quality gaps" that we encountered in the course of conducting this frequency response study for which we believe reasonable, short-term improvements are possible. As a result, 4 recommendations for consideration by the ERAG MMWG which the FRTF believes will provide quality improvements with respect to future frequency response related studies and which can be implemented in a relatively short time with relatively little additional data collection/maintenance burden for MMWG members. Recommendations are described in Section 7.

6.7 Task 7 – Identify Potential Improvements to Model Development Practices

The potential improvements identified are included with the recommendations detailed in Section 7.

6.8 Task 8 – Develop Process to Select Frequency Events to Test for the EI

The FRTF established a process to determine the MSSC and each member of the FRTF was asked to submit their region's MSSC. At the in-person meeting on April 9-10, 2018, the EIPC FRTF decided to use the NERC defined MSSC which is calculated and updated annually as part of BAL-002-2(i) Requirement R2. Members were given an opportunity to submit an excel file with the MSSC and MW amount lost included in the contingency. From these submissions, the largest MSSC for the EI included a combined generation of 2,576 MW.

6.9 Task 9 – Develop a List of Changes for Forward Looking Frequency Case

Simulations from Task 5 were compared to the April 8, 2017 event. It was concluded that the simulation with 55% of the governor models removed (only 45% responsive) would produce the closest result to the actual event. For Task 5, the following files were used.

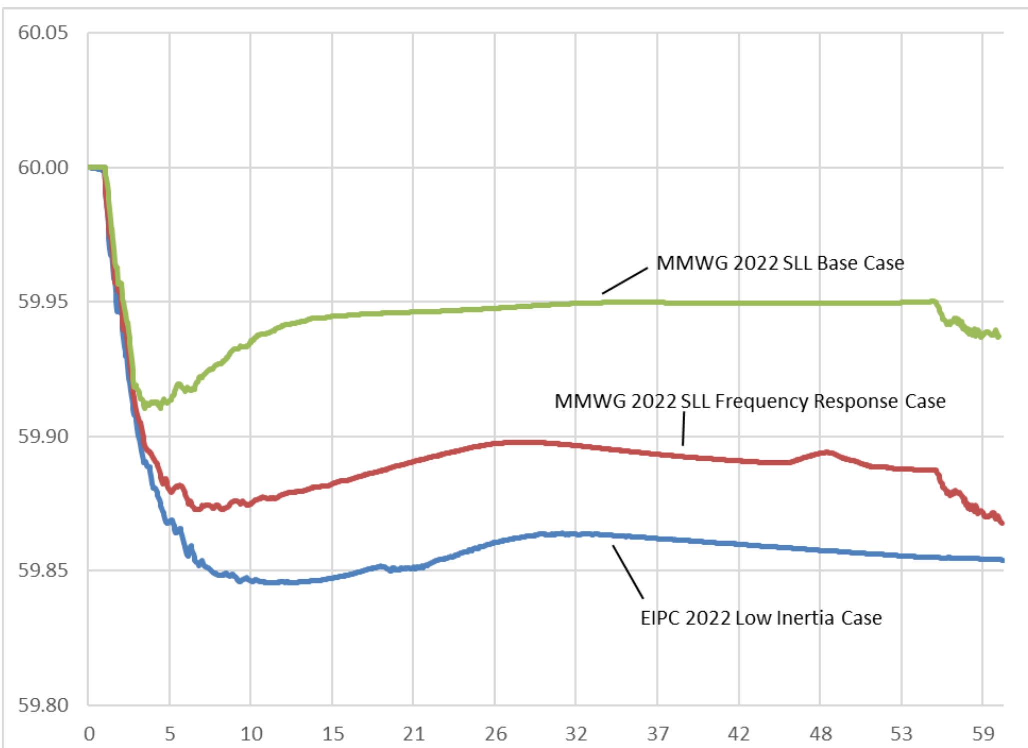
- Turn_Off_Gov.idv - This file changes the status of 8 WEHGOV models with generator real power outputs near their upper limits to "out-of-service." These models were causing PSS/E to crash when initializing the simulation.
- Turn_Off_30_Percent_Gov.idv - This file changes the status of 956 governor models to out-of-service.
- Turn_Off_55_Percent_Gov.idv - This file changes the status of an additional 771 governor models to out-of-service.

Together, these files removed 1,735 models from the simulation. These same files were used for the 5 years out MMWG case. The MMWG frequency response file was not included in the Task 5 or Task 10 simulations. This file removes 1,772 models, rather than changes the status of the models to out-of-service. This file also adds plant related models of designated types to an additional 584 machines. The file includes BAT_CHANGE_PLMOD_DATA which appears to be obsolete. The FRTF will work with the MMWG to improve this file as part of its future recommendations.

6.10 Task 10 – Apply Changes Outlined in Task 9 to Forward Looking Case

Using the list of changes developed in Task 9, the future 5-years-out MMWG 2022SLL case was modified so that it represented an expected future low inertia case. These changes were supplied by members of the FRTF and are based on projected changes to the generation resource mix projected to occur by 2022. Due to the limited available time to complete these simulations, modifications to dynamic models were not included in these changes besides the governor modifications derived from Task 5. The MMWG produced a version of the 2022SLL case which included disabled and squelched governor response for many generators in the EI. While this case was used as a starting point for these simulations, test event simulations were performed to determine the change in frequency response associated with these changes. Additionally, the governor model changes used to match the 2018SLL case to the benchmark April 8, 2017 event were applied to compare against the starting point cases. Figure 6-14 shows the incremental effect of these governor model changes to frequency response. The dynamics case initialized and solved for the timeframe of primary frequency response for resource contingencies identified in Task 8.

Figure 6-14: Comparison of Model Change Impacts to Frequency Response



6.11 Task 11 – Calculate ERSTF Measures

Measure 1 for the 5 year out case includes a calculation of the synchronous inertial response (SIR) for the 2022SLL low inertia dispatch case, which is 1,628,795 MVA-s. The results for the calculated total system synchronous inertia for each case is shown in Table 6-11. The Eastern Interconnection has no known critical synchronous inertia limits. The UFLS for the majority of the Eastern Interconnection is 59.5 Hz and a higher 59.7 Hz setting is used in Florida to address local issues. For the purposes of this interconnection-wide study, 59.5 Hz will be used as the EI UFLS threshold.

Table 6-11: ERS Measure 1 Calculated Synchronous Inertia for Assessment

Case Number	Case Name (e.g. 2021 SLL case)	Total System's Synchronous Inertia (MVA-s)	Total Non-synchronous Generation Dispatched (Pgen [%])	Total Synchronous Generation Dispatched (Pgen [%])	Total DC Tie-Line Imports (MW)	Total System Load (MW)
1	2022SLL w/ updated gen dispatch	1,628,796	8.7	91.3	3,393	288,143
2	2018SLL w/ updated gen dispatch	1,663,192	5.0	95.0	1,995	266,358

Measure 2 for the 5 year out case includes a calculation of the rate of change of frequency (RoCoF) at the minimum synchronous inertia conditions for each generation loss event simulated. This calculation includes measuring the change in frequency during the first 0.5 second following the initiation of the event. Results are shown in Table 6-12. The Rate of Change of Frequency calculation is given by the formula:

$$RoCoF_{0.5} = \frac{f_{0.5} - f_0}{t_{0.5} - t_0} = \frac{f_{0.5} - f_0}{0.5} \ \left[\frac{Hz}{s}\right]$$

Where:

f_0 = frequency measurement at t_0
t_0 = the time at which the disturbance occurs
$f_{0.5}$ = frequency measurement at $t_{0.5}$
$t_{0.5}$ = ½ second after the start of the disturbance

Table 6-12: ERS Measure 2 Calculated Rate of Change of Frequency (RoCoF) for Assessment

Case Count	Full Case Name, Year, and Load Conditions Description (e.g. 2021 SLL case)	$RoCoF_{RCC}$ [Hz/s]	$RoCoF_{0.5}$ [Hz/s]	Interconnection Comments
1	MMWG 2022 SLL Case – EIPC Low Inertia Dispatch	0.0853004215	-0.0565551072	Simulation of RCC included four units totaling 4,567.1 MW in place of the historic units due to unavailability

The median frequency values from multiple frequency channels spread across the EI were used to calculate Measure 4 for each generation loss event simulation. Measure 4 results are in Table 6-13.

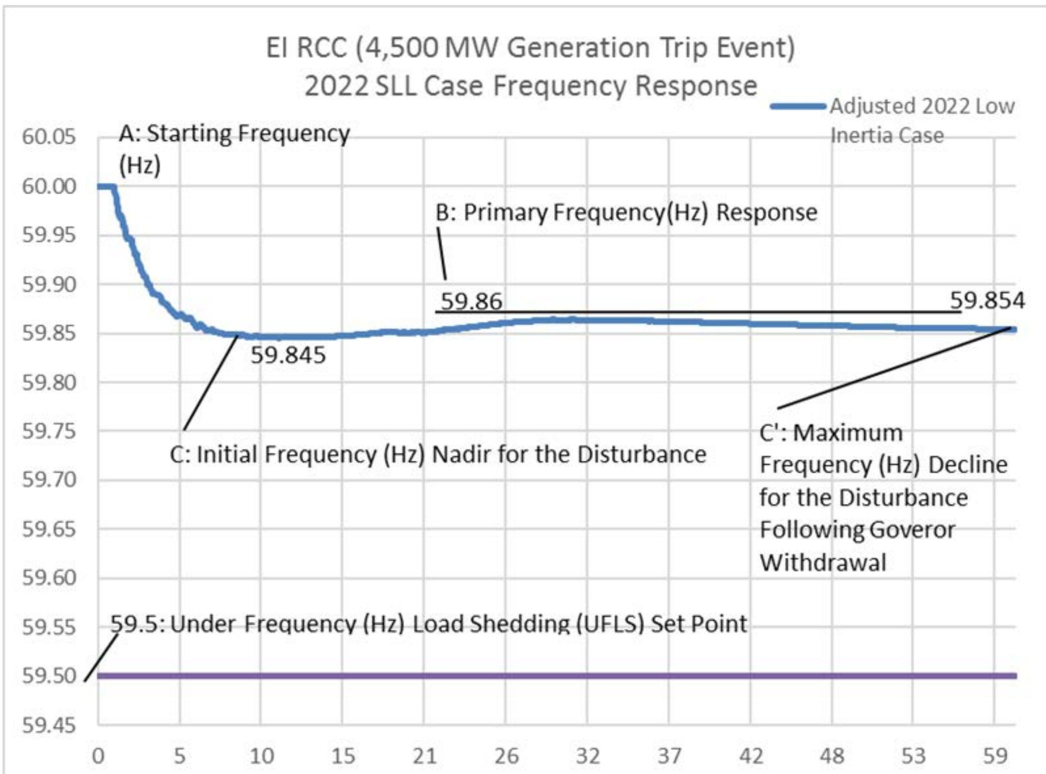
Table 6-13: ERS Forward Looking Measure 4 Interconnection Frequency Response for Assessment

Case Count	Full Case Name, Year, and Load Conditions Description (e.g. 2021 SLL case)	Performance Ratios				Time Calculations			
		A:B	A:C	C:B	C':C	$t_C - t_0$	$t_{C'} - t_C$	$t_{C'} - t_0$	Time to UFLS
1	MMWG 2022 SLL Case – EIPC Low Inertia Dispatch – EI 4,567 MW (Historic 2007) Contingency	3,277.971	2,974.792	1.102	0.944	10.396	48.605	59.001	0.345
2	MMWG 2022 SLL Case – EIPC Low Inertia Dispatch – EI 2,514 MW (MSSC) Contingency	3,252.391	3,031.631	1.073	0.996	12.017	46.984	59.001	0.416
3	MMWG 2022 SLL Case – EIPC Low Inertia Dispatch – EI 3,120 MW (Largest in 10 year) Contingency	3,171.714	2,934.269	1.081	0.972	10.846	48.155	59.001	0.393
4	MMWG 2022 SLL Case – EIPC Low Inertia Dispatch – EI 10,000 MW Contingency	3,283.203	2,813.671	1.167	0.867	11.292	47.259	58.551	0.144

6.11.1 Historic 4,500 MW Generation Trip Event

The first resource contingency simulated included the simultaneous loss of 4,500 MW. Since most of the units involved in this event were not dispatched online in the 2022 low inertia case, four units were selected across the EI which totaled up to 4,567 MW. The frequency response of the EI following the loss of this generation is shown in Figure 6-15. Measure 2 for this event calculates the initial frequency deviation during the first 0.5 seconds of the event. Measure 2 for the 4,500 MW historic generation loss event is -0.057 Hz. Measure 4 calculations for the 4,500 MW generation loss event include multiple aspects of frequency response for the EI and are listed in Figure 6-15.

Figure 6-15: Simulation of 4,500 MW Loss on 2022SLL Case w/ Low Inertia Disp



The FRTF raised concerns with the continued use of the 4,500 MW loss event as the 'benchmark' event for the EI. After discussions with the Planning Coordinator, the 2007 loss of generation event involving the loss of two units resulted from a complex series of events including:

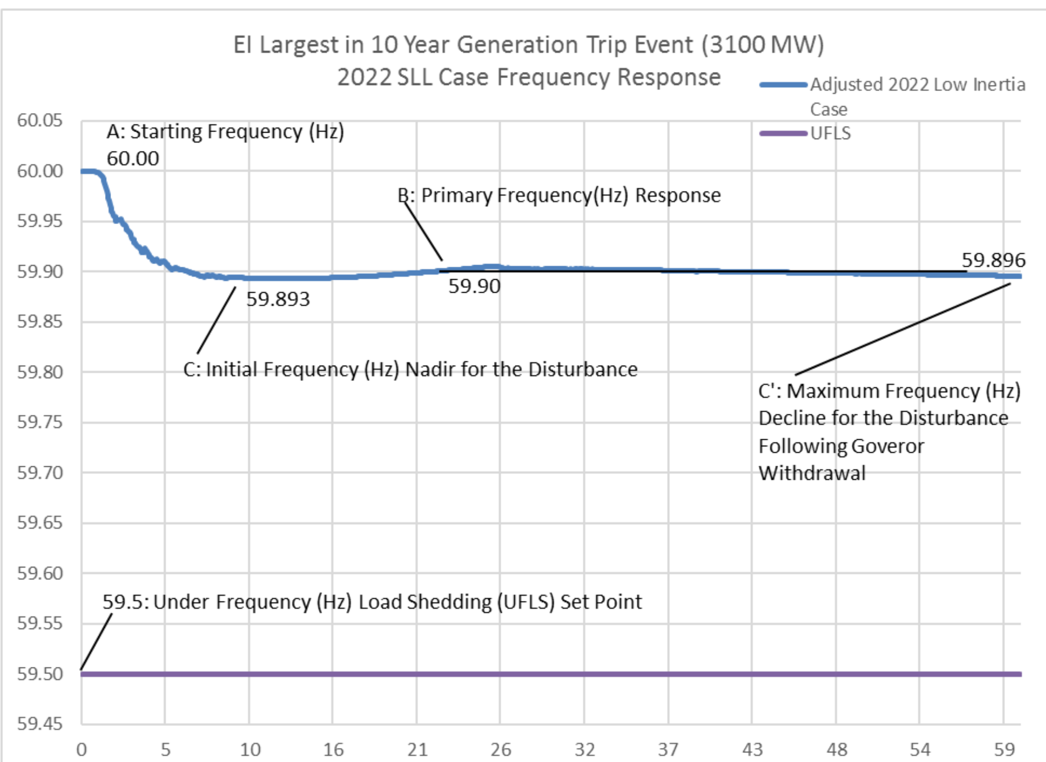
- A series of six (6) faults on a extra-high voltage (EHV) circuit
- An erroneous trip of a EHV circuit
- Multiple successive fast valving operations of the affected units
- Loss of two affected units

Two critical relay protection design errors related to the erroneous EHV circuit trip were identified and corrected shortly after the event. Today, the same sequence of events would not result in the EHV circuit trip. The fast valving controls the affected units have been modified to include multiple successive operations with a single unit trip as backup in the event of excessive boiler pressure. If the same fast valving sequence happened today it would only trip one unit. The result of these modifications is that, today, the same unlikely sequence of six intermittent faults on the EHV circuit would not be expected to result in the loss of the EHV circuit, nor would it be expected to result in the fast valving at the affected plant or unit tripping. In addition to the relay changes, one of the units that tripped during the event is no longer modeled in the MMWG cases. Based on those reasons, the FRTF recommended to NERC to no longer respect the 4,500 MW event and after preliminary discussions, NERC has agreed with the reasoning outlined by the FRTF.

6.11.2 The Largest 10-Year Event

In the period including 2008–2017, the single largest resource loss event occurred on April 27, 2011 with the loss of three units caused by a severe weather outbreak. The simulated frequency response of the EI following the loss of this generation is shown in Figure 6-16. Measure 2 for this event calculates the initial frequency deviation during the first 0.5 seconds of the event. Measure 2 for generation loss event is -0.038 Hz. Measure 4 calculations for the generation loss event include multiple aspects of frequency response for the EI and are listed in Figure 6-16.

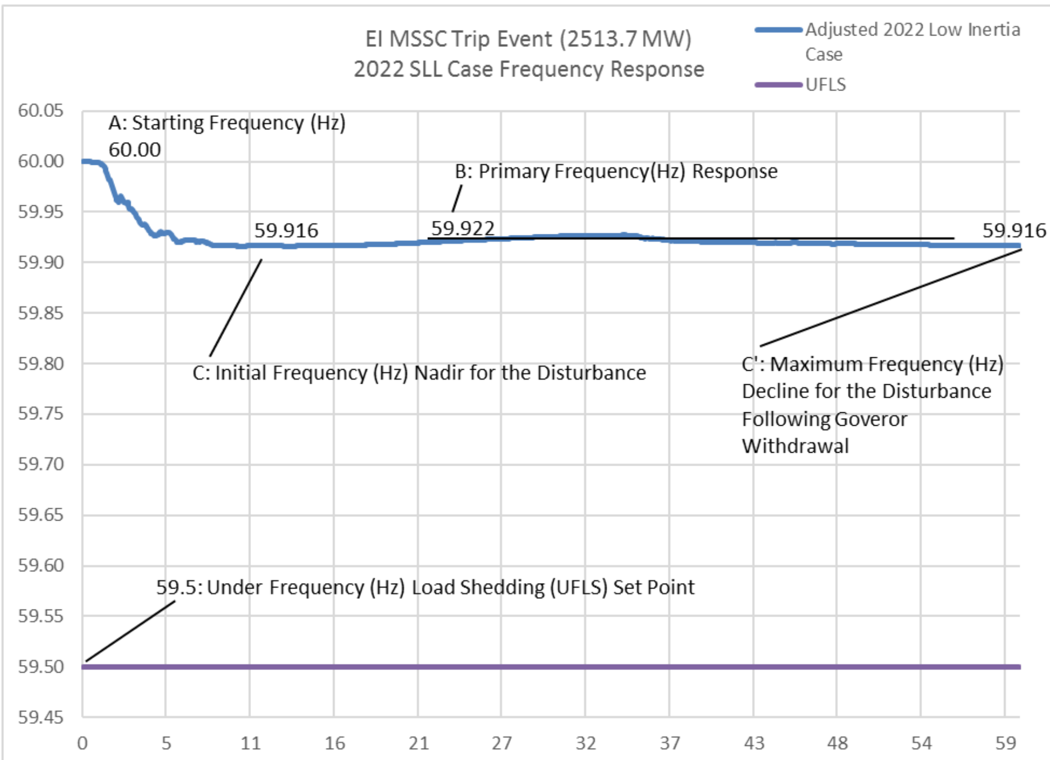
Figure 6-16: Simulation of 3,120 MW Loss on 2022SLL Case w/ Low Inertia Disp



6.11.3 The MSSC for the EI

Data for the EI including the MSSC for each BA covering the time period between March 2017 and April 2018 was collected. From this list of events, the largest event was selected for simulation. The selected event included a loss of 2,513.7 MW. The frequency response of the EI following the loss of this generation is shown in Figure 6-17. Measure 2 for this event calculates the initial frequency deviation during the first 0.5 seconds of the event. Measure 2 for the MSSC generation loss event is -0.028 Hz. Measure 4 calculations for the MSSC generation loss event include multiple aspects of frequency response for the EI and are listed in Figure 6-17.

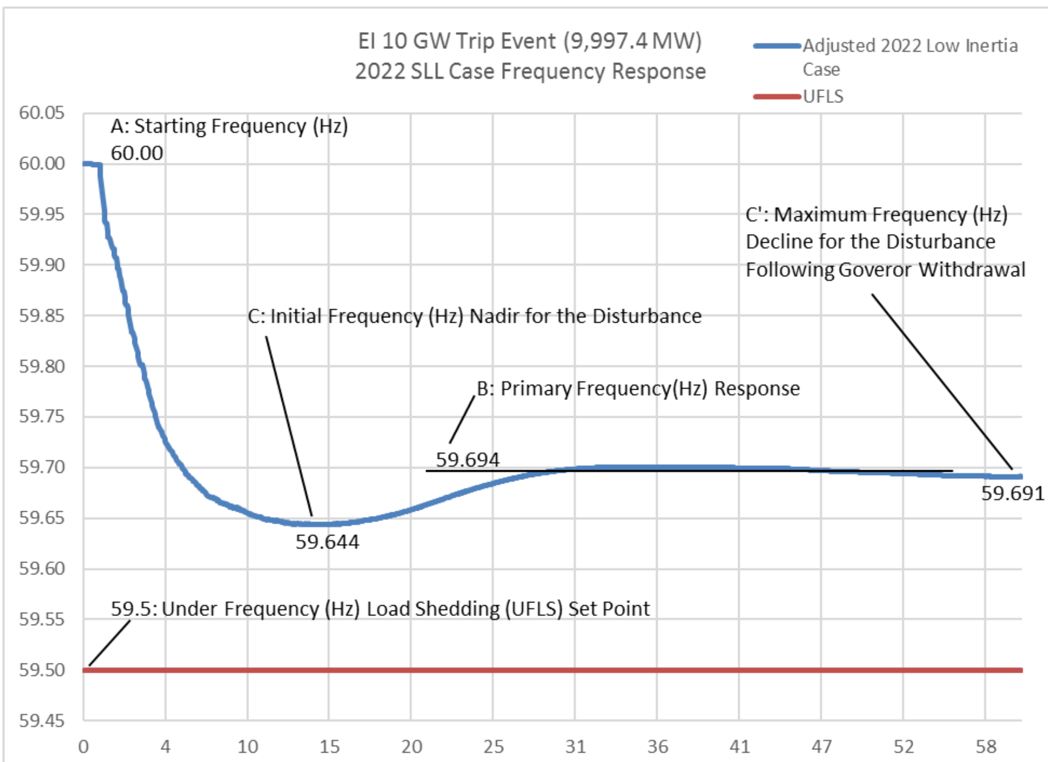
Figure 6-17: Simulation of MSSC 2,513.7 MW Loss on 2022SLL Case w/ Low Inertia Disp



6.11.4 Benchmark 10,000 MW Event

The last event simulated for the EI was a benchmark severe generation loss event which included the simultaneous loss of 10,000 MW within the EI. The frequency response of the EI following the loss of this generation is shown in Figure 6-18. Measure 2 for this event calculates the initial frequency deviation during the first 0.5 seconds of the event. Measure 2 for the 10,000 MW generation loss event is -0.155 Hz. The measure 4 calculations for the 10,000 MW generation loss event include multiple aspects of frequency response for the EI and are listed in Figure 6-18.

Figure 6-18: Simulation of 10,000 MW Loss on 2022SLL Case w/ Low Inertia Disp



6.12 Task 12 – Write an Internal EIPC Report and Submission to NERC LTRA of Results

This internal report has been written to document the process and findings of the FRTF's efforts. In addition, the FRTF submitted the ERSTF Measures 1, 2, and 4 to NERC for inclusion in the 2018 LTRA.

6.13 Task 13 – Outreach to Other Interconnections

The chair and vice-chair of the FRTF were on regular conference calls with NERC and the other interconnections (Western, Texas, and Quebec) to discussion submission of their results for the ERSTF Measures 1, 2, and 4 for the 2018 LTRA. All interconnections agreed to continue information sharing and ongoing conference calls to discuss frequency response related issues going forward.

Section 7 Recommendations

The following reflect the EIPC FRTF recommendations for improving the simulation study results of the MMWG base cases. The EIPC FRTF recognizes that compliance with the NERC Reliability Standards is the responsibility of the individual Planning Coordinators and Transmission Planners and does not intend to create any conflict with compliance with those standards.

7.1 Recommendation #1: Gross PMax Values

The MMWG should emphasize to generator data submitters the importance of using Gross MW capability for PMAX and inclusion of generator auxiliary load in the case models.

The MMWG Procedural Manual[5] in Section 8.2-D-4 states "Generator MW Limits – The generation capability limits specified for generators (PMIN and PMAX) should represent realistic continuous seasonal unit output capability for the generator in that given base case. ... *Gross maximum and minimum unit output capabilities should be used along with the unit auxiliary load modeled at the bus or buses from which it is supplied* (emphasis added)."

It is recognized that for power flow studies the emphasis tends to be more towards a generators ***Net*** MW output. This is generally appropriate for power flow purposes since it is only the Net MW that leaves a plant switchyard and affects general area flows. Additionally, Economic Dispatch is often based on Net generation. However, for frequency studies accurate representation the generator ***Gross*** MW output is necessary. Using Gross MW will more correctly represent the range of turbine-generator capability upon which a number of dynamics modeling parameters are based, as discussed in Recommendation #2. Additionally, generator auxiliary load represents several percent of the total Eastern Interconnection load being served and netting it out may result in some level of inaccuracy for frequency response study results. It is anticipated that additional discussions to determine how to best meet both the power flow and dynamics needs will be necessary.

7.2 Recommendation #2: Governor Modeling

The MMWG Planning Coordinators should emphasize to generator data submitters the importance of appropriate selection and coordination of the frequency and turbine-governor related model parameters such as Governor Droop, Governor Dead Band, and Maximum Turbine Power. This will likely need to be a longer term effort as data to populate the newer PSSE models which better represent these quantities become available.

The MMWG Procedural Manual[5] in Section 9.2-G states "Turbine governor models which represent dead band are recommended to be used. Starting with PSSE v33.10 dead band modeling is part of the suite of available models." However, while these improved dynamic models are now available in the current versions of PSSE being used for the MMWG annual update process, it will take some time before the data necessary to populate these models is available. Generator Owners are currently in various stages of completing the requirements of NERC Standard MOD-27.[6] In general, the validated models resulting from the MOD-027 effort would be expected to include dead band.

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[5] Multiregional Modeling Working Group (MMWG) Procedural Manual, Version 19, dated October 26, 2017.

[6] NERC Reliability Standard MOD-027-1, Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions.

In dynamics simulations, which are typically used for frequency related studies, Maximum Power is represented by quantities in the dynamics models for the turbine-governor, either directly or indirectly, and not by PMAX in the power flow. A "direct" example is the parameter Trate (e.g. in the GGOV1, GAST2A, HYGOVDU and other models), where maximum power is entered directly as a turbine MW value. Some "indirect" examples are parameters like Pmax (e.g. in the HYGOV2, IEEEG1 and other models) or Vmax (e.g. in the TGOV1, TGOV2 and other models), which reflect maximum power as a per unit quantity based on MBASE in the power flow. Whichever models are used, care must be taken to ensure that the turbine maximum power is correctly represented in the dynamics models in order to accurately reflect the amount of "headroom" available for frequency support.

Governor Droop (or the gain 1/Droop in some models) should reflect the droop based on the appropriate actual "zero-to-maximum turbine capability" range, not the "zero to MBASE" range. Depending on the model used and the data provided, it may be necessary to adjust the droop value to achieve reflect the actual droop based on the range of turbine capability.

Again, as discussed in Recommendation #1, Maximum Power related parameters should be based on ***Gross*** MW, not Net.

7.3 Recommendation #3: Frequency Responsive Dynamics Files

The MMWG should consider the benefits of including Load-Frequency Response Characteristic Models as part of the annual MMWG Dynamics Update process. If adopted, these should be provided as a separate dyr file and not incorporated into the case year files themselves.

Load frequency response is a significant contributor to slowing the decay of frequency, particularly in the initial seconds of a large generation loss (i.e. early in the primary frequency response part of the event). Having some modeling of this effect readily available as part of the MMWG series of case files might be beneficial for frequency related studies by the EIPC or other users of these cases. It is anticipated that the data provided would consist of a simple dyr file on an Area basis using a PSSE dynamic load characteristic model such as LDFRAR or similar. The MMWG could collect the input from individual submitters into a single dyr file applicable to all case years. Such data should generally be from the dynamic simulations performed at least every five years per NERC Standard PRC-006[7] (Automatic Under Frequency Load Shedding). UFLS settings, at least on an Area-wide basis, do not change frequently. Therefore, the data collection burden on MMWG members would be minimal.

Providing this data as a separate dyr file that would not be incorporated into the dynamics data files for each individual case year is desirable to avoid unnecessarily increasing the size and complexity of the individual case files with data that would not be used in the majority of studies/simulations performed. This concept is already being used for the complex load models provided for the MMWG annual updates.

7.4 Recommendation #4: Need for a Low Inertia / Minimum Load MMWG Library Case

The MMWG should consider the benefits of creating a new, or replacing an existing case(s) of the current library set that reflects a historically low inertia / minimum load time period for long-term power flow and transient stability models.

As this project progressed, it became readily apparent that the current set of library cases cannot accurately model a low inertia frequency response test given the current study periods included in the library set. The

[7] NERC Reliability Standard PRC-006-3, Automatic Under Frequency Load Shedding.

best option currently is the 5 year out SLL case. This case has 297 GW of load and 1,671 GVA-s of inertia online in the model. The lowest recorded inertia for 2017 provided by NERC reports 1,038 GVA-s of inertia at a EI load level of 215 GW. The inertia in the SLL case is 60.5% higher than the minimum observed inertia for 2017 and the load is 38.1% higher than what was observed during that low inertia event. For reference, the lowest load recorded in the EI for 2017 was even lower at 164 GW. These large differences made it difficult to represent an interconnection wide low inertia event using the existing case library without making significant changes.

The FRTF recommends two new library cases be created to represent the historically low inertia time period for both 1 and 5 years out. The near-term case would be used to verify the accuracy of the current stability models in response to a simulated frequency event compared to recorded NERC FNET data. The long-term case would be beneficial in tracking the projected further reduction in inertia expected with continual addition of non-synchronous resources across the interconnection. In addition to the transient stability benefits from these models, it would also benefit steady state power flow analysis to have a minimum load case to accurately account for high voltages seen on lightly loaded transmission.

Careful attention should be made by the PC submitting data to the MMWG to create representative base case dispatches for the low inertia events taking into account historical resource mixes, typical interchange during low inertia events, typical capacity factor of non-synchronous resources at low inertia time periods, amount of headroom remaining on dispatched units to account for spinning reserves, and projected additional non-synchronous generation coming online that will displace existing synchronous generation during low inertia time periods.

If these cases are built during the annual library case building process, the process to produce the Frequency Measures 1, 2, and 4 for the NERC LTRA will be much easier and future efforts can be made focusing on improving the dynamics models to more accurately reflect the actual projected system performance. The 1 year out case will allow for benchmarking to recent historical frequency events and the 5 year out case will allow for calculation of Measures 1, 2, and 4. At a minimum, the FRTF recommends the 5 year out case be included in the library if adding two cases to the library set is overly burdensome and existing library cases could not be removed from the list to be replaced by the low inertia cases.

Although this study indicates that system inertia and frequency response will be sufficient to prevent UFLS for even severe generation loss events, there is still a need to develop low inertia models for planning studies. Reduced system inertia may have localized impacts such as unexpected performance of remedial action schemes, out-of-step tripping relays, and other protection schemes. Studies of EI oscillations have indicated that lower inertia due to increasing penetration of non-synchronous resources may reduce the damping of existing oscillatory modes. Additionally, when performing studies restoration and other conditions where the system is already weakened, a lower system inertia will have a greater impact in the local area than when studying the entire interconnected system. A low inertia MMWG library case would readily enable these impacts to be studied by individual planning coordinators.

Section 8 Conclusion

This report details information on the technical analysis, model modifications, and simulations performed by members of the FRTF to assess the ERSWG forward looking frequency Measures 1, 2, and 4 for the EI for inclusion in the 2018 NERC LTRA.

With the addition of non-synchronous generation and planned synchronous resource retirements, questions have been raised about the ability of the EI to maintain frequency. The TC has been tasked with identifying and understanding how future generation contingencies could lead to UFLS events due to the reduction of frequency support from the changing generation resource mix. In order to study and plan for possible increased non-synchronous generation with reduced inertia, there is a need for improved frequency responsive power flow simulation models. With assistance from all of the FRTF members, biweekly meetings and collaborative efforts allowed the FRTF to develop, assign, and complete many tasks in support of this effort. The results of the analysis demonstrate the EI has sufficient system inertia over the next 5 years with planned resource retirements and non-synchronous resource additions.

In total, 13 tasks (described in Section 4) were completed. One of the tasks included benchmarking a historical frequency event with spring light load (SLL) cases to determine how the generator governor models performed in response to the simulated historical frequency events. Results concluded that the proportion of generators providing primary frequency response was higher than previous studies had determined. Based on efforts of the FRTF, approximately 45% of governors were modeled as in-service providing frequency response to match the historical frequency events. Previous studies from NERC suggested modeling roughly 30% of the governors in-service to benchmark against historical events. The FRTF determined this by visually comparing the simulation results with different percentages of governors disabled to the actual events. The results shown in Figure 6-6 and Figure 6-13 provided the best match to the actual events. For the forward looking frequency measures, 55% of the governors were disabled in the power flow model to match historical events.

A list of recommended changes to improve the frequency response of the planning models was developed as a result of this work and submitted for consideration to the MMWG in future model development cycles. It is expected future improvements to the modeling of governors through new compliance standards and updated simulation models from the software vendors will reduce the need for artificially disabling governor models to match historical performance.

The FRTF tested three different frequency events on a forward looking 2022 SLL MMWG power flow case. The events included the historical 4,500 MW event, the EI's MSSC, and the largest EI frequency event of the last 10 years. A 10,000 MW benchmark event was also tested to determine the amount of margin available in the EI system response. With 55% of the governors disabled based on the benchmarking analysis, generation power dispatch changes were made to the case to be similar to the lowest observed EI inertia event during 2017. The case also included future changes to synchronous generation retirements and non-synchronous generation additions expected in the next 5 years.

All three frequency events exhibited satisfactory frequency response with a minimum frequency (nadir) of 59.85 Hz, and the benchmark event had a nadir of 59.64 Hz. These are all significantly higher than the initial UFLS set point of 59.5 Hz. In other words, the system inertia and primary frequency response will be sufficient even with expected retirements of synchronous generation and increases in non-synchronous generation.

The results of the analysis were submitted for inclusion in the 2018 NERC LTRA. A set of recommendations for improvements to the MMWG case building process were also developed and the FRTF will work with the MMWG going forward to implement those recommendations. Details of the recommendations are described in Section 7.

- Recommendation #1: Modeling of Gross PMax Values in Case
- Recommendation #2: Accurate Governor Modeling in Case
- Recommendation #3: Addition of Frequency Responsive Dynamics Files to Library
- Recommendation #4: Need for New Low Inertia / Minimum Load MMWG Library Case

The FRTF would like to thank all members from the Planning Coordinators for the effort and participation to successfully complete the assigned tasks. The next steps for the FRTF will be to work with the TC and determine the next scope of work for the TF going forward.

Section 9 Appendix A: Review of Current Research

Report #1

Title	Dynamic Model Validation with Governor Dead band on the Eastern Interconnection
URL	http://info.ornl.gov/sites/publications/files/Pub48114.pdf
Summary	This report documents efforts to perform dynamic model validation in the EI by modeling governor dead band. Three case studies are evaluated by comparing actual frequency events (obtained from FNET/GridEye) to an MMWG model. Comparison is also made to the actual frequency event with an MMWG model adjusted to account for governor dead band.
Recommendations	It is concluded that simulated frequency response exhibits closer alignment with measurement by modeling governor dead band. The authors do recognize that modeling governor dead band does not resolve all issues in a low inertia case (one example shows different ring-down slopes).
Concerns	Dead band is implemented and adjusted uniformly between 30-40 mHz. No consideration is given to only applying dead band adjustments to units that are obligated per NERC MOD-027 to provide a verified governor model.

Report #2

Title	Eastern Frequency Response Study
URL	https://www.nrel.gov/docs/fy13osti/58077.pdf
Summary	This study was specifically designed to investigate the frequency response of the Eastern Interconnection (EI) that results from large loss-of-generation events of the type targeted by the North American Electric Reliability Corporation (NERC) *Standard BAL-003 Frequency Response and Frequency Bias Setting* (NERC 2012a), under possible future system conditions with high levels of wind generation. The main goals of this work were to: • Create a realistic baseline model of the EI for examining frequency response • Illustrate overall system frequency response • Investigate the possible impact of large amounts of wind generation • Examine means to improve EI frequency response, with the use of active power controls on wind plants.
Recommendations	This investigation was of limited scope. Additional study of the EI, including a wide range of possible operating conditions, along with various commitment and dispatch strategies with high levels of wind power, is recommended. Other aspects, including the impact of governor headroom and dead-band, load modeling, location of responsive reserves, and response to over-frequency events, should also be examined.
Concerns	Load controls without frequency bias are known to cause governor withdrawal. This study reinforces other work that identified this behavior as a significant concern. Further investigation into the institutional causes and mitigation of this behavior is needed.

Report #3

Title	Use of Frequency Response Metrics to Assess the Planning and Operating Requirements for Reliable integration of Variable Renewable Generation
URL	https://www.ferc.gov/industries/electric/indus-act/reliability/frequencyresponsemetrics-report.pdf
Summary	
Recommendations	
Concerns	

Report #4

Title	Frequency Response Initiative Report (NERC)
URL	http://www.nerc.com/docs/pc/FRI_Report_10-30-12_Master_w-appendices.pdf

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

Recommendations	• Recommend Plant level primary frequency response be a contractual requirement on new plant so not change order mid-commissioning • Clearly defined requirements (ex. ERCOT 5.78%) …also define what constitutes plant rated load (ISO, prevailing ambient, supplemental sources etc.) o Example, minimum of X % response in Y seconds for Z mHz change in frequency • Requirements will trickle down to turbine supplier • Plant level testing • Must coordinate frequency injection between systems
Concerns	Plant level load control. Plant –plant coordination with A/E. Open loop vs closed loop, steam unit considerations, coordination with turbine load controller etc. Simple algorithms, low or no cost in plant design phase. Also, does NOT address MOD standards (026/027)

Report #5

Title	Frequency Response Initiative Generator Event Survey
URL	http://www.nerc.com/pa/rrm/Webinars%20DL/Frequency_Response_Initiative_Generator_Survey_20161208.pdf
Summary	
Recommendations	
Concerns	

Report #6

Title	Frequency Response Assessment and Improvement of Three Major North American Interconnections due to High Penetrations of PV Generation
URL	Distributed to group via email
Summary	
Recommendations	
Concerns	

Report #7

Title	Analysis of Eastern Interconnection Frequency Response
URL	http://www.nerc.com/comm/OC/Documents/2016_FRAA_Report_2016-09-30.pdf
Summary	This report is the 2016 annual analysis of frequency response performance for the administration and support of NERC Reliability Standard BAL-003-1 – Frequency Response and Frequency Bias Setting. It provides an update to the statistical analyses and calculations contained in the *2012 Frequency Response Initiative Report* approved by the NERC Resources Subcommittee and Operating Committee and accepted by the NERC Board of Trustees. No changes are proposed to the procedures recommended in that report. This report, prepared by NERC staff,1 contains the analysis and annual recommendations for the calculation of the Interconnection Frequency Response Obligation (IFRO) for each of the four electrical interconnections of North America for the operational year 2017 (December 2016 through November 2017). This includes: • Statistical analysis of the interconnection frequency characteristics for the period January 1, 2012, through December 31, 2015. • Calculation of adjustment factors from BAL-003-1 frequency response events. • Dynamics analysis of the recommended IFROs. • Analysis of frequency profiles for each interconnection.
Recommendations	The **Interconnection Frequency Response Obligation** (IFRO**)** values are recommended to be fixed at the values calculated in the 2015 FRAA and currently in effect, until inconsistencies in the IFRO calculation outlined in this section are addressed. The IFROs are considered to be the minimum frequency response necessary for the interconnections to maintain reliability and avoid tripping load by under frequency load shedding programs. It has no direct relationship to Frequency Bias setting used by Balancing Authorities to prevent withdrawal of primary frequency response by automatic generator control (AGC) action.
Concerns	Analysis of the behavior of the IFRO calculations for each interconnection in response to trends in frequency response performance has identified inconsistencies in the IFRO calculation that need to be addressed immediately.

Report #8

Title	Dynamic Models for Turbine-Governors in Power Systems Studies
URL	http://sites.ieee.org/fw-pes/files/2013/01/PES_TR1.pdf
Summary	The importance of modeling turbine-governors for studies related to transient angular stability, frequency stability and control, and to a lesser extent small-signal stability
Recommendations	The type of models to be used for turbine-governors for power system studies
Concerns	The older models need to be consolidated with respect to the models per recommendations

Section 10 Appendix B: Frequency Response Components

1. **A to B frequency response** captures the effectiveness of primary frequency response in stabilizing frequency following a large frequency excursion. This Measure is the conventional means of calculating frequency response as the ratio of net MW lost to the difference between Point A and Point B.

   $$\textit{Frequency Response (Current)} = \frac{Generation\ Lost\ (MW)}{Frequency\ (A) - Frequency\ (B)}$$

   Trending ALR1-12 in MW/0.1 Hz year to year versus trending only system conditions will provide additional insights concerning primary frequency response levels and characteristics. ALR1-12 metric is already being used. However, trending it versus time does not provide information on how at similar system conditions the response is changing year to year.

2. **A to C frequency response** captures the impacts of inertial response, load response (load damping) and initial governor response (governor response is triggered immediately after frequency falls outside of a pre-set dead band; however, depending on generator technology, full governor response may require up to 30 seconds to be fully deployed). This Measure is calculated as the ratio of net megawatt lost to difference between Point A and Point C frequency.

   $$\textit{Frequency Response (Nadir)} = \frac{Generation\ Lost\ (MW)}{Frequency\ (A) - Frequency\ (C)}$$

   Trending this Measure year to year will capture effects of changes in generation mix and load characteristics and help identify needs for synchronous inertia and/or some forms of fast frequency response (e.g., from battery storage or load resources with under-frequency relays).

3. **C to B ratio** captures the difference between maximum frequency deviation and settling frequency. The C to B ratio is related to governor responsiveness with respect to frequency deviation reading, and their capability to arrest and stabilize system frequency.

   $$\textit{C:B Ratio} = \frac{Frequency\ (C) - Frequency\ (A)}{Frequency\ (B) - Frequency\ (A)}$$

   This Measure should also be trended year to year versus trending only system conditions to provide insight into the amount of generation providing primary frequency response compared with the total committed generation on-line.

4. **C’ to C ratio** is the ratio between the absolute frequency minimum (Point C’) caused by governor withdrawal and the initial frequency nadir (Point C).

   $$\textit{C':C Ratio} = \frac{Frequency\ (C') - Frequency\ (A)}{Frequency\ (C) - Frequency\ (A)}$$

In the Eastern Interconnection, the difference between Point C and Point C’ is of concern due to governor response withdrawal. While ALR1-12 data does not contain C’, original frequency data with 1-second resolution (which captures 300 seconds of an event) can be used. In the Eastern Interconnection, trending the difference between Point C and Point C’ for similar-sized events will capture whether Generator Owners are working with vendors to adjust plant Distributed Control Systems load controllers to mitigate the impact of governor response withdrawals.

5. **Time-based Measures** are used to capture the speed in which inertial and primary frequency response as well as governor withdrawal are occurring. These Measures can be trended year to year to identify trends in the rate of change of frequency decline and whether the governor withdrawal phenomena are trending toward improvement or further degradation. These Measures include:
   a. **tC-t0 Measure** is the difference in time between the frequency nadir and initial event. It captures the time in which system inertia and governor response arrest declining frequency to its minimum level. Trending this time difference can be useful for ensuring that the defined times for BAL-003-1 fit the actual event data. In addition, trending this with respect to event size and initial frequency can help identify how dead band settings play a role in frequency arrest.
   b. **tC’-tC Measure** is the difference in time between the governor withdrawal minimum and the initial frequency nadir. This Measure captures the time in which governor stabilization and withdrawal occur prior to secondary controls and load responsiveness beginning to return frequency to its initial value.
   c. **tC’-t0 Measure** is the difference in time between the governor withdrawal minimum and the initial event. This provides a comprehensive picture of the overall time in which frequency declines and continues to fall due to the initiating event. While C’ should be mitigated and eliminated entirely, the time between the initial event and absolute minimum should also be minimized. In the Eastern Interconnection, it is observed that the minimum frequency level (C’ value) due to governor response withdrawal generally occurs 59–78 seconds after an event.

It should be noted that historical trending of frequency response does not show aggressively degrading frequency response in any of the four interconnections. Efforts related to BAL-003-1 and surveying the Generator Owners regarding governor set point controls have proved effective in communicating the need for primary frequency response. The Measures outlined herein should be tracked for each interconnection such that frequency response can continue to be metricized year to year. If concerns arise and a notable decline in frequency response is observed, then NERC will explore root causes of the declining trends and appropriate action can be taken.